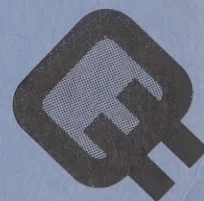# Electricity Costing and Pricing Study

Volume VIII

Detailed Rate Structure Design Proposals

October, 1976

ELECTRICITY COSTING AND PRICING STUDY

VOLUME VIII
DETAILED RATE STRUCTURE DESIGN PROPOSALS

Ontario Hydro
October 1976

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I. INTRODUCTION

In order to meet the efficiency objective, it is important for the price schedules to provide as much relevant cost information to the end user of electrical energy as is practicable. It is the end user who makes the marginal consumption decision, to turn off a light, or the television set, or to add a midnight shift to take advantage of off-peak prices. The incentive to take these actions is the price of electricity itself.[1]

The guiding principle, then, in designing a rate structure to meet the efficiency objective is to ensure that the marginal use of electricity is priced at the marginal costs of the generation and distribution systems, subject to the previously defined constraints of fairness and the revenue requirement. Rate structures were designed to illustrate the flow of the cost information from the bulk-power system, through the retailing entities, to the end customer, while picking up the distribution or delivery costs on the way. The resulting rate structure is called the 'flow-through' approach, because it 'flows' the marginal cost information from the producer, Ontario Hydro, through the distributors, the municipalities, to the end user of electricity. At the same time, the rate-structure proposals do not interfere with the local autonomy of the municipalities.

Thus the primary pricing-objective to be met in the proposed rate design is that it should contribute to the efficient allocation of resources devoted to producing electricity. There were two other guiding constraints in the design; namely, that the revenues generated by the rates should not exceed the revenue requirement, and that the rates should be as fair as practicable.

Fair means equal treatment of equals, based on criteria which reflect general consensus of the community. These criteria are the following:

1. The benefits of historical investment should be returned to the utility's customers through the price structure, in such a manner as to maintain distributional neutrality. That is, the benefits of historical investment should not be used to subsidize a particular group of customers at the expense of other groups.

2. The pricing-structure must maintain the integrity of the cost-pooling concept.

3. There should be no seniority rights in the pricing structure. All consumption is always new, for the decision to discontinue it can be made at any time.

4. The pricing structure should be impersonal, that is, there should be no undue discrimination; Any rate structure will be discriminatory to some degree; but the real question is whether the discrimination among customers can be justified.

5. The pricing structure and changes in the price level should be defined clearly so that the customer is aware of the price he will pay, for any specific course of action he undertakes. This is the criterion of certainty in prices.

6. A change in corporate policy, for example, a change in the reliability of the system, should not lead to unduly abrupt changes in prices or service received. This is the criterion of continuity in prices.

This volume contains the following parts:

II. Customer Classes and Pricing at the Bulk and Retail Level

This section outlines the proposed customer classes at both the bulk and retail levels, and gives a general over-view of the proposed approach to pricing.

III. The Revenue Requirement and Rate Structure

The revenue requirements at the bulk and retail levels are discussed in this section. In addition, the proposed demand/energy split is discussed, along with the proposed method of determining the revenue requirement for each customer group. Also included is an extended discussion on the revenue requirement and the historical benefits of investment.

IV. Rate-Structure Proposals for Large Users

The pricing methodology for large users is provided in Section IV. Illustrative rates and total bills are included, along with a comparison to the present rate structure.

V. Proposed Pricing-Methodology for Municipal Utilities

The detailed rate-structure proposals, and illustrative rate schedules for selected utilities are provided in Section V.

VI. Proposed Price Structures and Illustrative Price Schedules at the Retail Level

This section outlines the proposed approach to pricing for the small-use customers of retailing utilities. A detailed description of the proposed methodology, illustrative rate schedules, and a comparison to existing rates are given.

VII. Other Rate Issues

This section considers other rate issues which were analysed in the study. The cost-benefit studies assessing the feasibility of abandoning bulk metering and adopting time-of-day metering for small users are discussed. Three other rate issues are also discussed: the minimum bill, flat-rate water-heater service, and special rates.

Appendix I: Projected Rates for 1977, 1978, and 1979 Under the Present Pricing Methodology

This appendix provides the projected rates for 1977-1979, under the present pricing-methodology, for eight selected municipal utilities, Ontario Hydro's rural system, and Ontario Hydro's direct industrial customers.

Appendix II: Rationale for Folding the Demand Charge Into the Energy Charge for 0-50 kW Users

Appendix III: Rates and Bills for Large Electricity Users

The usage patterns of selected large users are used to illustrate the effect of the proposed pricing-rule for large users. Different cases are considered, including that of a growing peak customer, and a shift of peak to off-peak consumption. A comparison is made of the total bills under the proposed pricing-rule to the present rate structure.

Appendix IV: Proposed Future Method of Establishing Customer-Related Costs and Dealing with Surplus Revenue

This appendix outlines a methodology for determining customer-related costs and dealing with surplus revenues for customers of the retailing utilities below 5000 kilowatts.

Appendix V: A Resource Cost-Benefit Analysis of Bulk Versus Individual Metering of Apartment Buildings in Ontario

This appendix is a cost-benefit analysis, assessing the feasibility of abandoning bulk metering in apartment buildings.

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[1]Clearly the price of electricity is important as well in the initial 'stocking' decision, such as the decision to buy an electric clothes dryer, rather than a gas dryer or a clothes line (wind and solar power).

Appendix VI: Residential Time-of-Day Metering

This is the cost-benefit study assessing the feasibility of time-of-use rates for residential users.

II. CUSTOMER CLASSES AND PRICING AT THE BULK AND RETAIL LEVEL

A. CUSTOMER CLASSES AT THE BULK LEVEL

The present costing-classification of Ontario Hydro at the wholesale level is composed of 353 Municipal Utilities and the Power District, which is the retailing entity operated by Ontario Hydro. The total costs, associated with the common generating, or production, grid and radial transmission, or common delivery, costs, plus associated other joint and fixed costs, are allocated to each of the 354 customers in a uniform two-part rate. This rate consists of a single energy charge in mills per kilowatt-hour and a single load charge in dollars per kilowatt of demand. This demand charge, which is a rate-of-use charge, has generally represented more than 50 per cent of the total bill of each distributing utility. Each monthly total of the billed kilowatts of demand exceeds the total kilowatts of load for the system, due to the non-coincident feature of the billed kilowatts of each utility.

The total amount associated with kilowatts for the Power District are then assigned to the two classes: direct industrial and the rural retail system of Ontario Hydro, based on the non-coincident monthly demand of each. As this again exceeds the total billed demand of the Power District, the dollars per kilowatt of demand for the class of direct industrial customers is less than the dollars per kilowatt for the Power District.

A 100-per-cent load-factor Direct Industrial customer would impose a higher charge under this classification system on the Power District than a lower-load-factor customer, because of its coincidence with the peak of the Power District. As a result, demand and energy charges to these industrial customers have been adjusted in their rates to reflect this costing characteristic, and to reflect a diminishing benefit of diversity as the load factor increases. What this has meant is a lower demand and higher energy charge to the direct industrial customers than that made by or to the retailing utilities. This costing-method has generally led to a higher total bill for the utility for a load of similar shape and magnitude than for the direct industrial customer, given identical delivery conditions.

The larger industrial customers, have generally been concerned about the disparity between their rates and those of the municipal utilities. At the same time, large industrial customers of the municipal utilities have faced different monthly bills from Direct Industrial customers, and customers of other municipal utilities, for identical loads, load shapes, and delivery conditions. This is due to the anomalies of the customer classification and costing methodology. This has led to considerable debate, about the existing present system of classifying customers among the concerned parties, the large direct industrial customers, the retailing municipal utilities, and the large industrial customers of these utilities. Each of these groups is facing different demand and energy charges, and thus different total bills for identical load, load characteristics, and delivery conditions.

In order to minimize these differences, it is recommended that the unit rate for energy and rate of use of energy (kW) should be the same for similar delivery conditions to all large customers, thus eliminating charges of discrimination. That is to say, the rates to all large power users should be the same, if all other factors are the same. Because the characteristics of the large power user load are similar to those of all but the smaller utilities, the unit costs to the larger user group should be the same, under similar delivery conditions to those of the retailing utilities. If rates are to be cost-based and reflect cost causality, then the unit rate for demand and energy should be the same for customer groups (under similar delivery conditions). Only where

market characteristics of the customer groups are employed in rate-making, e.g. diversity considerations, would different unit rates to customer groups be justified. There would be, for costing purposes, then, a single class of customers comprising all retailing utilities, including Ontario Hydro's Rural Retail System, and all large industrial, commercial, or institutional users of electricity.

Large is defined initially to be those retail customers whose average monthly load is 5000 kilowatts or larger. It is the intent to reduce this level to 3000 kilowatts as soon as load data can be obtained and analysed for those customers with average monthly loads between 3000 kilowatts and 5000 kilowatts. The 3000 kilowatt level was selected because customers with loads greater than this are a relatively more homogeneous group. Most own their own transformation and protective switch-gear, they are generally not served off the distribution system and some already have digital demand recorders installed. This level was selected in the absence of data, and hence the final level could turn out to be above or below 3000 kilowatts. In the meantime, it is recommended that the 5000 kilowatt level should be retained for classification of large users.

The new classification, which would be a costing-classification, would consist of the sum of the net loads of all retailing utilities, including the retail system, plus the loads of all large users (initially 5000 kilowatts, eventually 3000 kilowatts as data becomes available). These large users are customers of the various retailing utilities. The retailing utilities' net costing load would not include any customer loads over 5000 kilowatts. Hence the total number of costing loads would be 354 Retailing Utilities plus approximately 201 Large Use Customers (those greater than 5000 kW).

The total number of costing loads is arrived at as follows:

1. Remove the direct customers' costing load from the Power District. Each direct customer would be costed on an identical basis with the Retailing Utilities. The resulting loss of diversity among the Direct Customers, and between the rural retail system and the directs, would lead to an increase in costs for the Directs of 16 million dollars in 1977. Conversely, this loss of diversity for the Retail System results in a decrease in its costs of one million dollars. The retailing utilities are not allowed diversity among themselves in the present classification, hence none is lost. This classification change would reduce their cost of power by 15 million dollars in 1977.

2. Remove the costing loads of the large users (loads greater than 5000 kilowatts) from the retailing utilities.

3. Add the monthly non-coincident loads of the large users, the 353 retailing utilities (net of large users), the rural retail system, and the 100 direct customers.

Since the costing loads of the large-use customers of the retailing utilities would not be included in the costing load of the utility under the proposed classification, the costs of the new group of large users would be increased by the equivalent dollar total of the cost reduction in the utilities' new costing load. This change does not effect any measurably significant cost re-allocation. Exhibit II-1 shows a comparison of class revenues in 1977, excluding the rate modification for the retailing municipal utilities, large users, and the rural retail system. It should be noted in examining the exhibit that the new classification contains twice the number of customers compared to the previous direct customer class.

All cost data estimates were prepared for the years 1977, 1978, and 1979, based on 30-per-cent, 15-per-cent and 10-per-cent increases in the respective years. All comparisons are for identical delivery conditions at at high voltage.

Exhibit II-2 shows the form of rate structure, excluding marginal costing charges, for 1977 under the existing classification, and under the proposed classification. A typical utility bill calculation for two large use customers under the proposed classification, in 1977, is shown in Exhibit II-3.

The recommended approach would enable smaller utilities to serve larger customers within their boundaries directly, without distorting the total bill received by the utility, its customers or the new large user. This costing anomoly may at present occur when a large user moves from the direct industrial class and peaks coincidentally with a utility's peak.

B. CUSTOMER CLASSES FOR THE RETAILING UTILITY

1. Large Users (Load Greater than 5000 Kilowatts)

As illustrated on Exhibit II-3, each large user will be costed separately at the bulk power level. Thus, a retailing utility serving a large user will receive a multi-component monthly bill for bulk power. One component will consist of the cost for the fully-diversified load of all the customers of the utility under 5,000 kW, and the remaining components will consist of a specific cost for each large user served by the utility.

The utility will, in turn, add to the bulk-power cost identified for each large user, any delivery, administrative, overhead, and any metering costs. The administrative and overhead costs do not vary with usage and are best suited to a special customer charge for the large users, which may vary between utilities.

In practice, the utility will issue a bill to each large user at month end as is done now. All costs incurred by the utility on behalf of the large users will be recovered on a monthly basis from the large users.

It should be stressed that suitable load and cost data must be obtained before the level can be reduced from the present level of 5000 kilowatts, to the recommended level of 3000 kilowatts.

2. Balance of Each Utility's Retail Load (Loads Less than 5000 kilowatts)

A single rate structure would apply to customers that comprise the retailing utility's load, net of large users. It should be noted that time variations in the marginal costs for both demand and energy have been averaged, both across the winter and summer peak periods, and across the off-peak periods. Sufficient load and cost data was not available to provide illustrative rate schedules. A cost-benefit analysis conducted on residential data did not indicate a clear benefit for seasonal time-of-day rates for residential users. A similar study, due to time and data constraints, was not conducted for the smaller number of industrial and commercial users of the general class in the small user group.

The rate structure to be known as the general rate for small users would consist of a three-part charge:

1. *A Customer Charge*, which would be a function of the customer-related costs, and the cost characteristics of the distribution system, which are independent of variations in the load demanded of the delivery system. This would produce several sub-classes with respect to the customer charge as discussed below.

2. *A Demand Charge* for all customer loads greater than 50 kilowatts. This demand charge would reflect the marginal costs of the generation and high voltage common facilities, and the marginal costs of sub-transmission and distribution facilities dependent on the transformation and voltage conditions of supply to the customer. The demand charge would be assessed on the basis of the customer's monthly non-coincident peak demand.

3. *An Energy Charge* for the first 10,000 kilowatt-hours of use reflecting the marginal energy costs of generation and marginal losses of the delivery system. The relevant marginal demand costs associated with the first 50 kilowatts of load would be folded into the energy costs above, based on the average monthly load factor of all consumption under 50 kW per month. This is consistent with past rate methodology for ensuring continuity in a rate schedule that moves from a pure energy rate to a demand/energy rate. A second block is suggested to be for 990,000 kWh per month. This would include marginal energy costs of generation, and marginal losses as appropriate to the point of delivery. The end rate would be set at an energy rate which would provide some coordination with the rate of the large-user group.

The marginal costs of generation, transmission, distribution and energy are discussed in detail in Volume Seven.

The end users fall then into two broad classes, based on rate of use:

1. Monthly maximum demand of greater than 5000 kilowatts, and

2. Monthly maximum demand of 0 to 5000 kilowatts.

This class would be divided into six user groups in Ontario Hydro's retail system, each with delivery systems that have different fixed cost characteristics.

These are similar to the present categories:

1. High-density residential, or R1;

2. Normal density residential and single-phase farm (R2 and F2-1);

3. High-density residential, intermittent occupancy (R3);

4. Normal density residential, intermittent occupancy (R4);

5. General, distribution voltage supply including three-phase farms (G and F2-3); and

6. General, sub-transmission voltage supply (T and G specials).

(G specials are customers under 5000 kilowatts administered at present by the Industrial Service Department because of contractual conditions).

The general class is subdivided into those customers supplied at distribution and those supplied at sub-transmission voltage levels to reflect the fact that sub-transmission voltage customers do not contribute to the cost of transformation to distribution voltage levels, or to the cost of the distribution voltage system.

EXHIBIT II-1

COMPARISON OF CLASS REVENUES
EXCLUDING RATE MODIFICATION
(EST. 1977 BASED ON 30% INCREASE)

	RETAILING MUNICIPAL UTILITIES			LARGE USERS					RURAL RETAIL		
	Demand	Energy	Total	Demand Mun	Dir	Energy Mun	Dir	Total	Demand	Energy	Total
EXISTING CLASSES Cost ($000,000)	607	515	1,122	116		150		266	133	118	251
No. of customers in class			353					100			1
EXISTING CLASSES less diversity Cost ($000,000)	542	515	1,107	145		138		283	131	118	249
PROPOSED CLASSES Cost ($000,000)	505	432	937	87	145	83	138	453	87	162	249
No. of customers in class			353					201			1

EXHIBIT II-2

FORM OF RATE STRUCTURE (EXCLUDING MARGINAL COSTING CHARGES)

UNDER THE EXISTING CLASSIFICATION FOR 1977 COST ESTIMATES (BASED ON A 30% INCREASE) THE RATES WOULD BE:

. Municipal Utility
  $5.18/kW + .85¢/kWh   kW: monthly non-coincident demand

. Direct Customer
  $4.05/kW + .925¢/kWh   kW: monthly non-coincident demand

. Rural Retail System
  $5.18/kW + .85¢/kWh   kW: monthly non-coincident demand

UNDER THE PROPOSED CLASSIFICATION FOR 1977 COST ESTIMATES (BASED ON A 30% INCREASE) THE RATES WOULD BE:

. All loads - Municipal Utility, Rural Retail System, Large User

  $5.02/kW + .0085/kWh   kW: monthly non-coincident demand

EXHIBIT II-3

TYPICAL UTILITY BILL CALCULATION WITH 2 LARGE USE CUSTOMERS
UTILITY LOAD (EXCLUSIVE OF LARGE CUSTOMERS) UNDER THE PROPOSED CLASSIFICATION

Average Monthly Non-coincident Maximum Demand = 470,000 kW
Average Energy = 147,000 GWh

Utility Bill for one month
= (470,000 x 5.02 + 147,000,000 x .0085) + Costing Bill 1 + Costing Bill 2

= ($2,359,400 + 1,249,500) + $100,310 + $212,600

= $3,608,900 + $100,310 + $212,600

Utility would add delivery plus a share of administration and overhead costs to
each Large Use customer's bill. Hence, bills to Large Use Customer #1, assuming
high voltage supply, would be:

Customer Charge + (10,500 x 5.02) + (5,600,000 x .0085)
= Customer Charge + $100,310

Large Customer #1

Average Monthly Non-coincident Demand   = 10,500 kW
Average Monthly Energy   = 5,600 GWh
Costing Bill #1 = 10,500 x 5.02 + 5,600,000 x .0085 = $100,310

Large Customer #2

Average Monthly Non-coincident Demand   = 20,000 kW
Average Monthly Energy   = 13,200 GWh
Costing Bill #2 = 20,000 x 5.02 + 13,200,000 x .0085 = $212,600

III. THE REVENUE REQUIREMENT AND RATE STRUCTURE

It is important to distinguish between the total revenue to be collected by Ontario Hydro, and the price structure employed to generate that revenue.

Common to all the pricing objectives and the associated rate structure is the revenue requirement constraint. Ontario Hydro is a non-profit organization, and in any given year it must recover its costs. The revenue requirement refers to the accounting costs of providing service in a given year, including net income to cover statutory debt retirement provisions, and any additional amounts needed for system expansion, and to preserve financial soundness. Hence, the revenue requirement determines the amount of money which must be obtained through rates. Similarly, each of the municipal utilities, also non-profit organizations, have a given revenue requirement which indicates the amount of money to be obtained through rates. The forecast revenue requirement for Ontario Hydro's bulk power system, in 1977, 1978, and 1979 dollars, is shown in Table 1.

TABLE 1

Projected Bulk Power Revenue Requirement
1977-1979*

Year	Projected Revenue Requirement
1977	$1,620,875,000
1978	$2,001,882,000
1979	$2,315,225,000

* Including interruptible power discount
and excluding non-common and retail
distribution costs.

Having determined the revenue requirement, it is necessary to allocate the total common costs of the bulk power system to demand or energy.

A. THE DEMAND-ENERGY SPLIT

The following point was made in Ontario Hydro's rate submission for 1976 *Report on Demand and Energy Rates for 1976*, on p. 1:

This subject was the centre of considerable controversy during the Ontario Energy Board Hearings in 1974. In its report, the Ontario Energy Board disagreed with the implication of a fixed target of a 50-50 split between demand and energy, and also with the speed of implementation of increases in the energy component. Since, in the Ontario Energy Board's view, Ontario Hydro had not provided an adequate basis for fixing the demand/ energy charge, the Ontario Energy Board recommended an energy charge of 4.5 mills/kWh as the rate for 1975, pending determination of an energy charge for 1976 and subsequent years.

This further comment was made on page 2 of that report:

The allocation of costs between demand and energy has been the subject of much investigation and discussion by supply authorities and regulatory commissions for many years. Various methods have been developed but all have been based necessarily on assumptions and opinions and are, therefore, largely judgmental.

At issue, then, is the appropriate basis for splitting total bulk power costs between demand and energy. The basis for the demand/energy split is important because of its implications for capital spending and the consumption of primary energy resources. Of course, any change in the demand/energy split also has cost impact implications for the customer.

The division of costs between demand and energy is necessary given the nature of the commodity. Kilowatt-hours, as such, cannot be stored. Because electricity cannot be stored, additional plant must be installed to serve the maximum or peak rate of use over a given time interval. This situation necessitates at least a two-part charge: an energy charge expressed in cents mills per kilowatt-hour, which reflects the customer's use of the commodity of electrical energy; and a demand charge expressed in dollars per kilowatt which reflects the rate of use of kilowatt-hours.

The relative price relationship between demand and energy, determined by the split of total common costs, can have a significant impact on the mix of input resources required, with respect to both capital and primary energy. The absolute price level for both demand and energy given by the split can affect the magnitude of basic input resources required, and the method of assigning demand costs to the customer can affect the quantity of basic input resources required. Potential shortfall of capacity varies according to the intensity of demand and reaches a peak during the time interval of maximum demand, in a day or, in a year. The planner is required to augment the system, in these maximum demand periods, as a result of the potential increase in load, while there is excess capacity at other times.

In order to achieve the proper mix of input resources, capital and primary energy, it has been proposed that the demand/energy split be based on marginal costs for both wholesale and retail customers. In order to achieve the proper magnitude of input resources, it has also been proposed that the demand and energy rates be set such that additional or marginal use by the energy customer is priced at the marginal costs of production. Further discussion of this subject is to be found in the NERA Marginal Costing Report in Volume VII.

The actual rate structure and associated schedules are discussed in the next three sections. The remainder of this section illustrates the revenue requirement for different customer groups.

Table 2 shows the proposed demand/energy split, based on marginal costs for 1977, 1978, and 1979, and the associated time-averaged unit cost of demand and energy in 1977 dollars

TABLE 2

Projected Demand/Energy Split Based on Marginal Costs
Time Averated and Prorated to the Revenue Requirements*
1977-1979

Year	Prorated Annual Demand Unit Rate $/kW	%	Prorated Energy Unit Rate ¢/kWh	%
1977	40	35	1.169	65
1978	47	35	1.335	65
1979	53	37	1.444	63

* Demand rates do not include the interruptible
power discount for large users.

or purposes of comparison, the expected demand/energy plit, and the associated average unit rates under the present ystem are shown for the same three years in Table 3.

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TABLE 3

Demand/Energy Split Based On
The Existing Rate Structure And
he Associated Average Unit Costs For Demand And Energy*
1977-1979

</div>

ear	Annual Demand Average Unit Rate $/kW	%	Energy Average Unit Rate ¢/kWh	%
977	65	55	.850	45
978	73	55	.950	45
979	81	55	1.050	45

Based on Financial Forecast 760529

should be noted that the unit costs in Table 2 are determined y calculating the marginal production costs for each of the cost haracteristics and prorating back to the revenue requirement. hese are hereafter referred to as the pro-rated unit costs. The ost differential between peak and off-peak energy would be aken into account. Table 4 illustrates the prospective marginal osts as calculated and not averaged through time. These are easonal demand, winter and summer peak energy and off-peak nergy split, based on marginal costs with the associated unit osts for each cost component.

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TABLE 4

Demand/Energy Split Based On
Time-Related Marginal Costs
Prorated to the Revenue Requirement
1977-1979

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	Demand - $/kW		Energy - ¢/kWh		
Year	Winter	Summer	Winter	Summer	Off-Peak
1977	33.19	5.54	1.45	1.24	.97
1978	38.80	6.47	1.68	1.39	1.10
1979	44.20	7.37	1.80	1.50	1.20

he pro-rated unit costs in Table 4 have been used to determine he revenues to be generated by each group of customers. That , the pro-rated unit costs have been used to determine the rev- nue requirement for the municipal utilities and large users. dded to these costs for each customer group would be the di- ect customer costs attributable to that customer group.

B. THE REVENUE REQUIREMENT AT THE BULK LEVEL

At the bulk level, the total revenue requirement cost shown in Table 1 has been allocated to the large users and the municipal tilities (including Ontario Hydro's rural retail system) using the

pro-rated unit costs from Table 4. This then would result in a different allocation of costs at the bulk power level than at present. The revenue requirement for the bulk power system was then divided into two component parts: the revenues to be generated by the net load of the retailing utilities, that is, the diversified load of the small user group, added to the revenues to be generated by the individual loads of the large users which are customers of the retailing utilities, or Ontario Hydro. These sub-revenue requirements were then determined by multiplying the pro-rated unit costs of demand from Table 4 by the respective usage figures for each group. With respect to the demand cost component, the proposed costing loads would be the sum of the individual monthly non-coincident peak demand of the 354 retailing utilities net of all large user loads over 5000 kilowatts. To this would be added the sum of the individual non-coincident monthly peak demands of the large users for the peak periods in each of the two six-month periods respectively, that is, October to March, and April to September. Hence, the demand charge that would apply to the six winter months would differ from that for the summer months. It should be noted again, that load data is not available for loads between 3000 and 5000 kilowatts. The analysis was therefore developed on the basis of extrapolated data for loads over 5000 kilowatts. Table 5 shows the division of the bulk revenue requirement between the municipal utilities, less large loads over 5000 kilowatts, and the large users of over 5000 kilowatts, using the unit costs from a demand/energy split based on marginal costs, pro-rated to the revenue requirement, as shown in Table 4.

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TABLE 5

The Division of The Bulk Power Revenue Requirement
Between The Municipal Utilities And Large Users
Assuming Seasonal Time-of-Day Projected Costs
1977-1979*

$'000

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Year	Bulk Power Revenue Requirement	Equals	Revenues Required from Municipal Utilities	Plus	Revenues Required from Large Users
1977	1,620,875		1,187,288		443,587
1978	2,001,882		1,430,577		571,305
1979	2,315,225		1,623,904		691,321

* Including interruptible power discount, and
   excluding non-common and retail distribution
   costs.

The revenue generated by pricing for the large users, on the basis of marginal costs outlined in the next section, would yield the revenue shown in Table 5, neither more nor less. It is important to recall that the total revenue required from the large-user group would be determined from a cost allocation based on pro-rated unit costs. As a group, then, they would receive the same benefits of historical investment under the proposed rate schedules based on marginal costs, as they would under a rate schedule based on pro-rated unit costs.

This methodology, then, ensures distributional neutrality at the bulk-power level; that is, avoidance of cross-subsidization among customer groups. It is true that strict marginal cost pric-

ing would presently lead to surplus revenue. However, it is possible, as is shown later, to depart in an optimal way from strict marginal cost pricing, while still meeting the efficiency objective, and giving the different customer groups the historical benefits of investment in the same proportion as under average cost pricing.

C. THE CLASS REVENUE REQUIREMENTS AT THE RETAIL LEVEL

All retail customers of less than 5,000 kW form one of the two major customer classes outlined in this report, the other class consisting of the large users. The first class would face one common rate structure in each utility. Due to the large numbers of small customers in this class, there may not be a net benefit in using a time-of-use form of rates. However, for the variable costs of energy (kWh) and the rate of use of energy (kW), a consistent set of rates, reflecting the marginal costs of electricity, averaged over time, would apply to all customers for each utility. This approach reduces substantially the number of different sets of rates.

Traditionally, the customers of under 5,000 kW have been separated into three main classes: residential, commercial, and industrial. The rates for each were based on their varying share of electricity costs for the utility, and the varying use they made of the utility's distribution system. On this latter point, it is proposed to isolate the fixed cost characteristics, which do vary between classes, but do not vary with usage (kW and kWh), as a customer charge. The revenue requirements of each class, then, need only include, in the limiting case, the prospective incremental differences between these costs. It should be noted, however, that this approach is not unique and should be subject to further analysis. On this basis, a uniform downward adjustment may be made in the customer charge until the revenue from kilowatts and kilowatt-hours sold, added to the avoidable customer costs, or customer charge, equals the total costs of operation for the utility.

Thus, a common rate structure would exist for all customers of a retailing utility. However, there would be differing customer charges for different sub-classes of customers. The differing customer charges are a function of the differing cost characteristics of the delivery system, for relatively homogeneous groups of customers.

D. THE REVENUE REQUIREMENT AND THE BENEFITS OF HISTORICAL INVESTMENT: AN ELABORATION

The reason that the customers of Ontario Hydro receive the benefits of historical investment is based on the revenue requirement and not the rate structure. The rate structure simply provides the vehicle by which the benefits of historical investment are returned to the customer. The revenue requirement is based on historical accounting costs, thus ensuring, in periods of inflation, that the customers receive the benefits of lower-cost historical investment. The point can be more fully appreciated by looking at a hypothetical example.

Consider an individual who bought nine identical houses in 1973. Assume that he rented out all the houses at a price just sufficient to recover his carrying-charges and taxes. In 1973, the total cost of these amounted to $900 per month for the nine houses. Each house, then, was rented out for $100 a month. The landlord had no problem renting out the houses, so he bought another identical house in 1974. Because of rising house prices and interest rates, the carrying-charges on this new house were $120 per month.

In order to keep his book-keeping simple, the landlord averaged the carrying charges and taxes of the tenth house with those of the original nine houses. This averaging resulted in a rental charge of $102 per month for each of the ten houses. The occupants of all ten houses shared in the benefits of historical investment, derived from the original nine houses.

Because the man found that it was very easy to rent out houses, he bought an eleventh house in 1975, and a twelfth house in 1976. Both were identical to the original nine. In each year, housing prices increased, leading to higher carrying charges and taxes. Acting as before, the landlord averaged in these new, higher costs with the older lower housing costs, and charged the same rent for all twelve houses in 1976. Exhibit III-1 shows the landlord's transactions and rents over the four-year period from 1973 to 1976.

As can be seen in column 3 of the exhibit, the landlord's total operating costs for the twelve houses houses was $1272 in 1976. This figure can be called the landlord's revenue requirement. To determine the rental charge on each house, the landlord simply divided his revenue requirement by the number of houses. In 1976, the total market rental value of the twelve houses was $1536 per month, which is simply the marginal cost of the 1976 house multiplied by the number of houses. The dollar total of benefits of historical investment is equal to the market rental value of the twelve houses, less the landlord's revenue requirement. In column 7 it can be seen that the total of the benefits of historical investment in 1976 was $264 per month. These were shared equally by all the tenants in the form of lower rents, lower by $22 per month. The landlord received none of the benefits of historical investment.

Leaving aside the landlord's rental policy and its implications, it should be clear that the benefits of historical investment result from the difference between the revenue requirement, based on historical accounting-costs, and the current market rental value of the houses. The example can be applied to public utilities as well.

As long as the revenue requirement is based on historical accounting costs, there will be benefits associated with historical investment in periods of inflation, diseconomies of scale, due to increasing social costs, for example, and technological restraint. It should be pointed out that circumstances could lead to a burden associated with historical investment. In a period of economies of scale and technological change, such as Ontario Hydro's early years, a revenue requirement based on historical accounting-costs would mean the burden of historical investment would have been shared by the utility's customers. This would be a decreasing-cost situation, where the marginal costs of production would be below the average costs.

EXHIBIT III-1

HYPOTHETICAL LANDLORD'S TRANSACTIONS

1973-1976

(1) Year	(2) Houses	(3) Total Operating Costs Per Month (Landlords Revenue Requirement)	(4) Average Operating Cost Per House Per Month (Rental Charge) (3) ÷ (2)	(5) Operating Costs of Last House Bought Per Month (Marginal Cost)	(6) Total Market Rental Value of Landlords Houses Per Month (5) x (2)	(7) Total Benefits of Historical Investment Shared by Tenants (6) - (3)
1973	9	$900	$100		$900	0
1974	10	$1020	$102	$120	$1200	$180
1975	11	$1144	$104	$124	$1364	$220
1976	12	$1272	$106	$128	$1536	$264

IV. RATE STRUCTURE PROPOSALS FOR LARGE USERS

A. Introduction

As was indicated, the large-user group would be composed of those end-user customers with a monthly power demand in excess of 5000 kilowatts, (eventually, 3000 kilowatts). Designing a rate structure which ensures that marginal use of demand and energy is priced at marginal cost, while meeting both the revenue requirement of the group, and the fairness criteria, is relatively straightforward. This is because the large use group has relatively few customers,[2]
and the metering equipment necessary for time-of-use pricing is already installed for many of these customers.

The large user would face a four-part charge, consisting of the following parts:

1. Demand Charge

The demand charge would be based on the marginal capacity costs associated with rate of use. Each customer's demand charge would be based on its monthly non-coincident peak demand during the daily peak period 0700 hours to 2300 hours, Monday through Friday, excluding statutory holidays.

The monthly demand charge would also vary between the winter season, October to March, and the summer season, April to September.

The use of non-coincident peak demand, in the peak period for each customer, was selected after consideration of several alternative methods of assigning peak period capacity costs to customers. The methods considered included loading all marginal capacity costs on to peak-period kilowatt-hours and making no demand charge, and charging customers on the basis of their demand for kilowatts during the system peak, as measured at twenty-minute intervals. There were two fundamental reasons for selecting the use of the customer's average monthly non-coincident peak in the peak period. First, the probability that demand will exceed capacity tends to be reasonably uniform throughout the peak period. As a result, it is equally probable that the customer will contribute to the system peak regardless of the occurence of his non-coincident peak in the peak period. Second, the use of the customer's non-coincident peak minimizes the probability of the 'needle-peak' phenomenon occurring, because of time-of-use pricing.

There would be no off-peak demand charge at present. This is because the relative loss of load probability between the daily peak and off-peak period is about 20 to 1. As a result, the administrative costs of an off-peak demand charge tend to outweigh the potential benefits of theoretical purity. However, as the relative loss of load probability between peak and off-peak changes in response to time-of-use pricing to around 10 to 1, the need for an off-peak demand charge will arise.

Not only do the marginal costs of providing electrical energy vary by time of day, but also by time of year. The loss of load probability in the winter is greater than in the summer. As a result, it is proposed that the winter peak period demand charge be greater than the summer charge in order to accurately reflect this seasonal cost differential.

2. Peak Energy Charge

The peak energy charge would be based on the seasonal marginal running costs associated with providing energy in the daily peak period of 0700 hours to 2300 hours, Monday through Friday, exclusive of statutory holidays.

3. Off-Peak Energy Charge

The off-peak energy charge would be based on the marginal running costs associated with providing off-peak energy, from 2300 hours to 0700 hours, Monday through Friday, and 24 hours a day on weekends and statutory holidays.

4. Customer Charge

The customer charge would be based on the dedicated costs of serving each customer, such as metering and billing, plus those costs which do not vary with output. At the bulk level, customer costs are very small in relative terms, have been omitted from the illustrative rate schedules for that reason.

B. ADJUSTMENT IN THE EVENT OF SURPLUS REVENUE

Notionally, the adjustment to the customer charge would be made in such a way as to ensure that the marginal price paid for kilowatts and kilowatt-hours by the customer is based on marginal cost. It is important here that the efficiency objective be preserved. As will be demonstrated, this is equivalent to pricing marginal use at marginal cost, which is the necessary and sufficient condition for the efficiency objective to be preserved. Thus, in an *ex ante* sense all use is priced at marginal cost. In an *ex poste* sense, only the change in the quantity demanded is priced at the marginal cost with the intra-marginal units priced at a costing average so as to balance revenues generated with the revenue requirement.

The credit applied to the customer charge can be calculated as follows:

1. The unit surplus for each cost component, peak kilowatt-hours, off-peak kilowatt-hours, and kilowatts, would be determined. The unit surplus is simply equal to the difference between the marginal cost and the costing average.

2. The unit surplus for each component would be multiplied by the individual customer's usage of peak kilowatt-hours, off-peak kilowatt-hours, and kilowatts, three years prior to the current billing year respectively. Hence, in 1977 the customer's credit for peak kilowatt-hours would be equal to the unit surplus in 1977, multiplied by the customer's use of peak kilowatt-hours in 1974. This procedure would be applied to each cost component to arrive at the customer's total credit. The rationale for using lagged usage figures is to minimize distortions to the efficiency objective.

The three-year rolling time period reflects the upper-limit payback period required by industry for most investments, other than those for major plant or locational. The pay-back period is used as an estimator of the criteria employed by the large power user in making his marginal consumption decision.

A less than three-year separation between baseline and current usage could result in industry responding to the baseline rate rather than the marginal price. On the other hand, marginally pricing growth over a period of greater than three years is likely to be inconsistent with the principle of continuity in rate structure. A numerical illustration of this principle appears in the accompanying tables.

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[2]At the same time, the large-user group accounts for a significant share of system load.

Numerical Illustration of
Large-User Pricing Rule

Chief Assumptions:

1. Four-Customer System

2. No Inflation

3. Example Use, Peak Energy Components

4. One-Year Lag Also Used For Illustrative Purposes

5. 1977 Average Cost Peak Energy of $.014

6. 1977 Marginal Cost Peak Energy of $.021

7. 1976 System Peak Energy of 400,000 kWh

8. 1977 System Peak Energy of 440,000 kWh

1977 Revenue Requirement
440,000 x $.014 = $6,160

1977 Revenues Using only Marginal Costs
440,000 x $.021 = $9,240

Resulting Surplus Over Revenue Requirement
$9,240 - $6,160 = $3,080

Calculation of Unit Average Costing Rate (UACR)

$$UACR = \frac{(1977\ Rev.\ Rqmt.) - (Marg.\ Cost \times Growth\ kWh)}{1976\ Peak\ Energy}$$

$$= \frac{\$6,160 - (\$.021 \times 40,000\ kWh)}{400,000\ kWh}$$

$$= \$.0133$$

CUSTOMER A

1976 Peak Energy 100,000 kWh
1977 Peak Energy 90,000 kWh

AVERAGE COST PRICING

1977 Bill = Average Cost x 1977 Usage
          = $.014 x 90,000 kWh
          = $1,260

MARGINAL COST PRICING

1977 Bill = ($.0133 x 1976 Usage)
          - (Marginal Cost x Reduced Energy)
          = ($.0133 x 100,000 kWh) - ($.021 x 10,000 kWh)
          = $1,330 - $210
          = $1,120

CUSTOMER B

1976 Peak Energy 100,000 kWh
1977 Peak Energy 100,000 kWh

AVERAGE COST PRICING

1977 Bill = Average Cost x 1977 Usage
          = $.014 x 100,000 kWh
          = $1,400

MARGINAL COST PRICING

1977 Bill = ($.0133 x 1976 Usage)
          + (Marginal Cost x Growth kWh)
          = ($.0133 x 100,000 kWh) + ($.021 x 0 kWh)
          = $1,330 + $0
          = $1,330

CUSTOMER C

1976 Peak Energy 100,000 kWh
1977 Peak Energy 110,000 kWh

AVERAGE COST PRICING

1977 Bill = Average Cost x 1977 Usage
          = $.014 x 110,000 kWh
          = $1,540

MARGINAL COST PRICING

1977 Bill = ($.0133 x 1976 Usage)
          + (Marginal Cost x Growth kWh)
          = ($.0133 x 100,000 kWh) + ($.021 x 10,000 kWh)
          = $1,330 + $210
          = $1,540

CUSTOMER D

1976 Peak Energy 100,000 kWh
1977 Peak Energy 140,000 kWh

AVERAGE COST PRICING

1977 Bill = Average Cost x 1977 Usage
          = $.014 x 140,000 kWh
          = $1,960

MARGINAL COST PRICING

1977 Bill = ($.0133 x 1976 Usage)
          + (Marginal Cost x Growth kWh)
          = ($.0133 x 100,000 kWh) + ($.021 x 40,000 kWh)
          = $1,330 + $840
          = $2,170

SYSTEM SUMMARY

Customer	1976 Energy (kWh)	1977 Energy (kWh)	Average Cost Pricing Revenues $	Marginal Cost Pricing Revenues $
A	100,000	90,000	1,260	1,120
B	100,000	100,000	1,400	1,330
C	100,000	110,000	1,540	1,540
D	100,000	140,000	1,960	2,170
TOTAL	400,000	440,000	6,160	6,160

Thus,

400,000 x $.014 = $6,160 under Average Cost Pricing

and,

(400,000 x $.0133) + (40,000 x $.021)
= $5,320 + $840
= $6,160, under Marginal Cost-Pricing with the
         Proposed Large-User Pricing-Rule

To sum up, the over-riding concern in choosing an appropriate time period was to ensure the integrity of the price signal in a large user's decision-making process.

More importantly, the method of determining the credit insures

that the marginal use of electricity is priced at its marginal cost. Consider the following simplified model where only kilowatt-hours are priced on the basis of marginal cost. The total bill faced by the customer in 1977 may be expressed as in Equation 1.

1. $TB = M\Delta q + A_{qo}$, where

  1. TB = total bill;

  2. M = marginal cost per kWh;

  3. A = costing-average per kWh;

  4. $_{qo}$ = kWh used by customer X in 1974;

  5. $_{q1}$ = kWh used by X in 1977;

  6. Δq = change in use of kWh by customer X between 1974 and 1977: that is $\Delta q = q_1 - q_o$;

  7. Q_1 = total kWh produced by utility in 1977;

  8. Q_o = total kWh produced by utility in 1974;

  9. S = total surplus in 1977, that is MQ_1-RR;

  10. s = component surplus in 1980, that is, M-A; and

  11. RR = revenue requirement in 1977 = $M\Delta Q + AQ_o$.

Hence Equation 1 shows the proposed large user pricing rule. Marginal use is priced at marginal cost, thus preserving the efficiency objective. At the same time no excessive revenues will accrue to Ontario Hydro.

It should be noted that, notionally, the costing average A would be equal to the pro-rated unit cost if there had been no growth. It would reflect technological or inflationary changes. However, because of the specific application to the large user group alone, the costing average reflects the costs of the average system growth rate as well as technological and inflationary changes. If the large-user pricing rule was applied to both the retailing utilities as well as the large power users, then the costing average would be, notionally, as described.

In order to see how the credit is determined for each customer, one may simply reformulate Equation 1:

2. $TB = Mq_1 - M_{qo} + A_{qo}$
$TB = M_{q1} - q_o(M-A)$

Recall that M-A is equal to s, the component surplus.

3. $TB = M_{q1} - s_{qo}$

where M_{q1} indicates that the marginal price is always marginal cost, and

s_{qo} is the credit for customer x.

The above notional formulation can be more simply stated as follows: While each large user pays the marginal cost for his marginal use of each component, i.e., demand and energy, the intra-marginal rate for each component is adjusted so as to ensure that the total revenue from the large-user group equals their revenue requirement as determined through pro-rated unit costs. Indeed, this is how the actual pricing methodology works, and this outlined in the next section.

C. DESCRIPTION OF PRICING METHODOLOGY

The proposed methodology for pricing for large users will be illustrated using a single costing and billing characteristic: peak kilowatt-hours. As shown in equation 1 above, the large user's total bill for this single characteristic would appear as follows: $TB = M\Delta q + A q_o$.

In order to make such a rate structure operational, it is necessary to know M, the marginal energy cost of peak kilowatt-hours, A, the costing-average of peak kilowatt-hours, the growth peak kilowatt-hours, and the base-year peak kilowatt-hours.

The marginal energy cost per kilowatt-hour data for 1977, 1978, and 1979 was taken from the marginal cost analysis undertaken by NERA.

In order to calculate the costing-average for peak kilowatt-hours the following procedure was developed. First, it was necessary to determine the revenue requirement for peak kilowatt-hours for large users. This information was taken from the proposed demand/energy split data, based on marginal costs for the three-year period. This revenue requirement is then equated to the sum of the cost of new peak kilowatt-hours, plus the cost of base-year peak kilowatt-hours. This may be expressed symbolically as follows: 4. $RR = M\Delta Q + AQ_o$, where RR = revenue requirement for peak kilowatt-hours, Q_o = base year peak kilowatt-hour use for the large use group, and ΔQ = change in peak kilowatt-hour use between the current billing year and the base year for the large user group.

Now, all cost and usage figures are known, except the costing-average. Hence it is necessary to solve Equation 4 for A, which yields $AQ_o = RR - M\Delta Q$; 5. $A = (RR-M\Delta Q)/Q_o$. That is, in order to derive the costing-average, it is necessary to subtract the marginal cost of the growth peak kilowatt-hours from the revenue requirement for peak kilowatt-hours. The resulting figure is then divided by base period peak kilowatt-hours in order to yield the costing-average of peak kilowatt-hours for large users.

The above methodology was employed to develop the costing-average in the three study years 1977 to 1979 for energy (winter peak, summer peak, and off-peak), and demand (winter and summer).

Exhibit IV-1 shows the marginal cost rates and indexed average cost for 1977, 1978, and 1979. The symbolic calculation of a large user's total annual bill is shown in Exhibit IV-2.

EXHIBIT IV-1

MARGINAL-COST RATES AND COSTING-AVERAGE-COST RATES
FOR THE LARGE-USER GROUP
1977-1979

Bill Component	1977		1978		1979	
	MC*	CAC**	MC	CAC	MC	CAC
Energy:	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh
Winter Peak	2.1	1.357	2.3	1.38	2.4	1.47
Summer Peak	1.8	1.162	1.9	1.14	2.0	1.22
Off-Peak	1.4	.907	1.5	.9	1.6	.98
Demand:	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
Winter	7.77	5.15	8.56	6.02	9.52	6.37
Summer	1.30	.86	1.43	1.01	1.59	1.06

* Marginal-Cost
** Costing-Average-Cost

EXHIBIT IV-2

SYMBOLIC CALCULATION OF LARGE-USER TOTAL ANNUAL BILL

$$
\begin{aligned}
\text{Total annual bill} = {} & M\ kWh' + A\ kWh'_o \\
\text{plus } & M\ kWh'' + A\ kWh''_o \\
\text{plus } & M\ kWh''' + A\ kWh'''_o \\
\text{plus } & M\ kW' + A\ kW'_o \\
\text{plus } & C
\end{aligned}
$$

where:

kWh' = growth winter peak kWh
kWh'_o = base year winter peak kWh
kWh'' = growth summer peak kWh
kWh''_o = base year summer peak kWh
kWh''' = growth off-peak kWh
kWh'''_o = base year off-peak kWh
kW' = growth in winter peak period maximum demand
kW'_o = base year winter peak period maximum demand
kW'' = growth in summer peak period maximum demand
kW''_o = base year summer peak period maximum demand
C = customer charge
M = respective marginal cost-based rates
A = respective costing average cost rates

D. COMPARISON WITH EXISTING RATE STRUCTURE

A full comparison of the proposed rates with the existing rate structure can be seen in Exhibit IV-3. For the three study years 1977 to 1979, the following four rate systems are shown:

1. Rates under the existing pricing methodology;
2. Rates using marginal costs prorated to meet the revenue requirement;
3. Seasonal time-of-day rates, using marginal costs prorated to the revenue requirement; and
4. Seasonal time-of-day rates, using marginal costs, where marginal use is priced at marginal cost.

The implications of these rates for the large user's total bill is analysed in depth in Appendix III of this volume. The prospective 1977 total bills of fifteen randomly selected large-user customers have been estimated for each of the above four rate structures. Appendix III also shows the detailed numerical calculation of the costing averages, the customer's total bill, and the impact on the total bill of a growing customer, and non-growing customer.

In summary, the following observations may be made about the rate structure proposals for large users:

1. The proposed rates will track costs, by season and by time of day, for demand and energy.
2. Marginal use of demand and energy would be priced at their respective marginal costs, thereby minimizing the wasteful use of electricity, which could occur if prices did not track costs.
3. The benefits of historical investment received by the large-user group under the marginal-cost rate proposals are the same as they would receive under average-cost pricing with a demand-energy split based on time-differentiated marginal costs.

Consideration should be given to conducting further analysis in order to assess the feasibility of applying the large user pricing rule to small users. For example, it may be feasible to implement this pricing rule, over a ten-year period, for that group of users whose monthly non-coincident demand is between 1000 kilowatts and 3000 kilowatts.

EXHIBIT IV-3
1977 LARGE USER RATES

LOAD PERIOD

RATE SYSTEM	MONTHLY SUMMER PEAK DEMAND $/KW/Mo.	MONTHLY WINTER PEAK DEMAND $/KW/Mo.	SUMMER PEAK ENERGY ¢/KWH	WINTER PEAK ENERGY ¢/KWH	OFF PEAK ENERGY ¢/KWH
Rates Under Existing Pricing Methodology	4.05	4.05	0.925	0.925	0.925
Rates Using Marginal Costs Pro-Rated to meet Revenue Requirement	3.255	3.255	1.157	1.157	1.157
Seasonal Time of Day Rates Using Marginal Costs Pro-Rated to Revenue Requirements	0.923	5.532	1.24	1.45	.97
Seasonal Time of Day Rates Using Marginal Costs where Marginal Use (increment or decrement in customer's load) is priced at Marginal Cost	MARGINAL RATE 1.30 COSTING AVG. 0.86	MARGINAL RATE 7.77 COSTING AVG. 5.15	MARGINAL RATE 1.8 COSTING AVG. 1.162	MARGINAL RATE 2.1 COSTING AVG. 1.357	MARGINAL RATE 1.4 COSTING AVG. .907

* At 115 kV - FIRM (Other Classes of Power will require corresponding adjustments in rates)

EXHIBIT IV-3   Page 2
1978 LARGE USER RATES

LOAD PERIOD

RATE SYSTEM	MONTHLY SUMMER PEAK DEMAND $/Kw/Mo.	MONTHLY WINTER PEAK DEMAND $/Kw/Mo.	SUMMER PEAK ENERGY ¢/KWH	WINTER PEAK ENERGY ¢/KWH	OFF PEAK ENERGY ¢/KWH
Rates Under Existing Pricing Methodology	4.53	4.53	1.025	1.025	1.025
Rates Using Marginal Costs Pro-Rated to meet Revenue Requirement	3.805	3.805	1.321	1.321	1.321
Seasonal Time of Day Rates Using Marginal Costs Pro-Rated to Revenue Requirements	1.078	6.467	1.39	1.68	1.10
Seasonal Time of Day Rates Using Marginal Costs where Marginal Use (increment or decrement in customer's load) is priced at Marginal Cost	MARGINAL RATE 1.43 COSTING AVG. 1.01	MARGINAL RATE 8.56 COSTING AVG. 6.02	MARGINAL RATE 1.9 COSTING AVG. 1.14	MARGINAL RATE 2.3 COSTING AVG. 1.38	MARGINAL RATE 1.5 COSTING AVG. .9

* At 115 kV - FIRM (Other Classes of Power will require corresponding adjustments in rates)

EXHIBIT IV-3
1979 LARGE USER RATES

L O A D   P E R I O D

RATE SYSTEM	MONTHLY SUMMER PEAK DEMAND $/KW/Mo.	MONTHLY WINTER PEAK DEMAND $/KW/Mo.	SUMMER PEAK ENERGY ¢/KWH	WINTER PEAK ENERGY ¢/KWH	OFF PEAK ENERGY ¢/KWH
Rates Under Existing Pricing Methodology	5.04	5.04	1.125	1.125	1.125
Rates Using Marginal Costs Pro-Rated to meet Revenue Requirement	8.668	8.668	1.43	1.43	1.43
Seasonal Time of Day Rates Using Marginal Costs Pro-Rated to Revenue Requirements	1.23	7.37	1.50	1.80	1.20
Seasonal Time of Day Rates Using Marginal Costs where Marginal Use (increment or decrement in customer's load) is priced at Marginal Cost	MARGINAL RATE 1.59 COSTING AVG. 1.06	MARGINAL RATE 9.52 COSTING AVG. 6.37	MARGINAL RATE 2.0 COSTING AVG. 1.22	MARGINAL RATE 2.4 COSTING AVG. 1.47	MARGINAL RATE 1.6 COSTING AVG. .98

* At 115 kV - FIRM (Other Classes of Power will require corresponding adjustments in rates)

V. PROPOSED PRICING-METHODOLOGY FOR THE MUNICIPAL UTILITIES

The municipal utilities are distributors of electrical energy to their end users, and this allows them little opportunity to respond to price signals. For the municipal utilities, it is proposed that rates should be based on marginal costs, pro-rated to the revenue requirement.

It should be noted, however, that the electricity use of the end customer of the retail system would be priced on the basis of marginal costs. The recommended pricing guidelines for retail customers are outlined in the next section.

The municipal utilities would face a two-part charge. One part of the charge would be for those customers with monthly power demands greater than 5,000 kilowatts on an individual-customer basis. The recommended pricing methodology for these customers was covered in the last section. Those marginal delivery costs incurred by the municipality in serving these large users (plus a contribution to utility overhead costs) would be assessed to the large user.

For the remainder of each municipality's load, it is proposed that rates be based on prorated unit costs. The prorated unit costs of demand and energy, and winter peak, summer peak and winter and summer off-peak energy, would be determined by splitting the total revenue requirement by the proportions obtained through the marginal cost study. More particularly, this part of the load of each municipal utility would face a charge with the following four parts:

1. Demand Charge

The demand charge would be based on the prorated cost associated with rate of use. Each municipal utility's demand charge would be based on the utility's monthly non-coincident peak demand during the (relevant) peak period.

2. Peak Energy Charge

The peak energy charge would be based on the prorated costs associated with providing energy in the relevant peak period.

The winter peak period consists of the hours between 0700 and 2300, Monday to Friday, exclusive of statutory holidays, from October through March. The summer peak period consists of the hours between 0700 and 2300, Monday to Friday, exclusive of statutory holidays, from April through September.

3. Off-Peak Energy Charge

The off-peak energy charge would be based on the prorated costs associated with providing off-peak energy, that is, from 2300 hours to 0700 hours, Monday through Friday, and 24 hours a day on weekends and statutory holidays, or the hours of the year, less the peak hours.

4. Customer Charge

The customer charge would be based on the costs that are associated with serving each municipal utility, and do not vary with output.

The symbolic representation of the proposed rate structure for the municipalities is shown in Exhibit V-1.

EXHIBIT V-1

SYMBOLIC CALCULATION OF A MUNICIPAL UTILITY'S ANNUAL BILL

```
Total Annual Bill = A kWh'
                plus   A kWh"
                plus   A kW'
                plus   A kWh"'
                plus   A kW"
                plus   C
```

where:

```
kWh'   = current year's winter peak kWh
kWh"   = current year's summer peak kWh
kWh"'  = current year's off-peak kWh
kW'    = current year's winter peak period maximum demand
kW"    = current year's summer peak period maximum demand
C      = customer charge
A      = respective prorated unit costs based on
         prorated marginal costs
```

Exhibit V-2 shows illustrative rate schedules for a typical municipality, 1977 to 1979.

EXHIBIT V-2

Illustrative 1977, 1978, 1979
Municipality Rate Schedule

	1977	1978	1979
LOADS			
Winter Total Six-Month Demand Charge	$33.19/kW	$38.80/kW	$44.20/kW
Summer Total Six-Month Demand Charge	$ 5.54/kW	$ 6.47/kW	$ 7.37/kW
ENERGY			
Winter Peak Charge	1.45¢/kWh	1.68¢/kWh	1.80¢/kWh
Summer Peak Charge	1.24¢/kWh	1.39¢/kWh	1.50¢/kWh
Off-Peak Charge	.97¢/kWh	1.10¢/kWh	1.20¢/kWh

It should be observed that the proposed prorated rates reflect the relevant rates of substitution between demand and energy, between peak and off-peak energy, between winter and summer peaks, in both kilowatts and kilowatt-hours.

There are two final observations that can be made about the proposed rate structure at the bulk level:

1. They maintain the local autonomy of the municipal utilities.

2. The group of large users as a whole pays the prorated unit cost. Hence, both municipal utilities and large users are costed on an equal basis. At the same time, each large user faces a rate where its marginal use is priced at marginal cost.

A full comparison of the revenues under the new classification.

Exhibit V-3

E F F E C T S   O F   M A R G I N A L   C O S T I N G

1977

COMPARISON OF REVENUES
NEW CLASSIFICATION
MARGINAL COSTING (BULK POWER LEVEL)

	RETAILING MUNICIPAL UTILITIES			LARGE USER			RURAL RETAIL		
	Demand	Energy	Total	Demand	Energy	Total	Demand	Energy	Total
EXISTING COSTING METHOD Cost ($000,000)	505	432	937	232	221	453	131	118	249
Demand/Energy Split		54/46			51/49	(see Note 3)		53/47	
MARGINAL COSTS PRORATED TO REVENUE REQUIREMENT Cost ($000,000)	337	594	931	154	305	459	87	162	249
Demand/Energy Split		36/64			34/66			35/65	
SEASONAL TIME-OF-DAY RATES MARGINAL COSTS PRORATED TO REVENUE REQUIREMENT *Costs ($000,000)									
- Winter Peak Hours	293	214	507	129	98	227	80	56	136
- Summer Peak Hours	44	158	202	21	77	98	11	43	54
- Off Peak Hours	-	226	226	-	126	126	-	63	63
	337	598	935	150	301	451	91	162	253
Demand/Energy Split		36/64			33/67			36/64	

Notes:

(1) * Winter Peak Hours: Months–January, February, March, October, November, December
Days–Monday to Friday exclusive of Statutory Holidays
Hours–0700 to 2300

Summer Peak Hours: Months–April, May, June, July, August, September
Days–Monday to Friday exclusive of Statutory Holidays
Hours–0700 to 2300

Off Peak Hours: Remainder of hours in year

(2) Demand charge based on the monthly non-coincident demand.

(3) The existing demand/energy split for the Directs under the present classification and rate structure is 33/67.

<u>EXHIBIT V-4</u>

FORM OF RATE STRUCTURE WITH SEASONAL TIME-OF-DAY RATES USING
MARGINAL COSTS (1977 RATES APPLY)

. MUNICIPAL UTILITY (INCLUDING RURAL RETAIL) PRORATED TO REVENUE
  REQUIREMENT

	Demand Charge	Energy Charge
Winter Peak Hours	$5.53/kW	$.0145 / kWh
Summer Peak Hours	$ .92/kW	$.0124 / kWh
Off-Peak Hours	-	$.0097 / kWh

The above schedule also applies to the total Large User group thereby
determining the revenue requirements. However, for individual members
of the Large User group the pricing rule is marginal use of marginal
cost and intramarginal use at a costing average. Since any increase
or decrease in use is charged or rebated at marginal costs then the
decision to increase or reduce load is thereby based on marginal costs.
Thus, the marginal use is the change in consumption. The increase or
decrease in use is calculated on a month-by-month basis on a rolling
three-year time lag. The following is the rate schedule.

. LARGE USER IN 1977

	Demand Charge	Energy Charge
Winter Peak Hours	$5.15/kW$\pm$$7.77/ΔkW	1.357¢/kWh$\pm$2.1¢/ΔkWh
Summer Peak Hours	$ .86/kW$\pm$$1.30/ΔkW	1.162¢/kWh$\pm$1.8¢/ΔkWh
Off-Peak Hours	0	.907¢/kWh$\pm$1.4¢/ΔkWh

kW = non-coincident load in 1974 in the corresponding costing period
ΔkW = increase or decrease in non-coincident load in 1977
kWh = kilowatthour usage in 1974 in the corresponding costing period
ΔkWh = increase or decrease in kilowatthour usage in 1977

and the rate proposals at the bulk power level for 1977, is shown in Exhibit V-3. The exhibit also shows the change in the demand-energy split resulting from the rate proposals.

Exhibit V-4 shows the proposed rate structure in 1977, with seasonal time-of-day rates using marginal costs for municipal utilities and the large users.

Given the above rates, Exhibit V-5 shows a typical bill calculation for a municipal utility with two large use customers, one which has shown increased growth, the other, reduced growth.

EXHIBIT V-5

TYPICAL BILL CALCULATION 1977 RATES

LOAD DATA FOR A TYPICAL WINTER MONTH

(a) UTILITY

Peak Demand	470,000 kW
Peak Energy	130,000,000 kWh
Off-Peak Energy	128,000,000 kWh

(b) CUSTOMER #1

Peak Demand (1974)	10,000 kW
(1977)	12,000 kW
Peak Energy (1974)	2,500,000 kWh
(1977)	3,000,000 kWh
Off-Peak Energy (1974)	3,200,000 kWh
(1977)	3,800,000 kWh

(c) CUSTOMER #2

Peak Demand (1974)	10,000 kW
(1977)	8,000 kW
Peak Energy (1974)	2,500,000 kWh
(1977)	1,800,000 kWh
Off-Peak Energy (1974)	3,200,000 kWh
(1977)	2,600,000 kWh

TOTAL BILL CALCULATION

CUSTOMER #1

$(\$5.15 \times 10,000 + \$7.77 \times 2,000)$
$+ (\$.01357 \times 2,500,000 + .021 \times 500,000)$
$+ (\$.00908 \times 3,200,000 + \$.014 \times 600,000)$
$= \$67,040 + \$44,425 + \$37,424$
$= \$148,889$

CUSTOMER #2

$(\$5.15 \times 10,000 = \$7.77 \times 2,000)$
$+ (\$.01357 \times 2,500,000 - .021 \times 700,000)$
$+ (\$.00907 \times 3,200,000 - \$.014 \times 600,000)$
$= \$35,960 + \$19,225 + \$20,624$
$= \$75,809$

UTILITY

$(\$5.53 \times 470,000 + \$.0145 \times 130,000,000 + \$.0097$
$\times 128,000,000) + \$148,889 + \$75,809$
$= (\$2,599,100 + \$1,885,000 + \$1,241,600)$
$+ \$148,889 + \$25,809$
$= \$5,725,700 + \$148,889 + \$75,809$

The percentage shift in class-cost allocations for 1977, as a result of the the classification change and rate changes is shown in Exhibit V-6.

EXHIBIT V-6

SHIFT IN CLASS COST ALLOCATIONS* Based on 1977 Cost Estimates			
	Municipality	Large Users	Rural Retail System
1. Cost Allocation Changes	-0.23%	-2.88%	+1.47%
2. Classification Change	-1.42%	+6.16%	-0.50%
3. Demand/Energy Split Based on Marginal Costs	-0.68%	+1.28%	-0.23%
4. Seasonal Time-of-Day Rates Based on Marginal Costs	-0.37%	-1.98%	+1.92%
NET CHANGE	-1.96%	+2.58%	+3.16%

NOTE: FOR PURPOSES OF COMPARISON IT WAS ASSUMED THAT NO CHANGE IN USAGE WOULD OCCUR IN THE LARGE USER GROUP.

* +: increase   -: decrease

Finally, Exhibit V-7 summarizes rate comparisons for 1977, 1978, and 1979 among the municipalities, large users, and the rural retail system. The monthly and annual rates, billed usage, and total costs are shown for each group in each of the following cases:

1. Existing rate structure and classes, less diversity;

2. Existing rate structure and proposed classes;

3. proposed classes, with demand and energy based on marginal costs prorated to the revenue requirement; and

4. proposed classes, with seasonal time-of-day rates based on marginal costs pro-rated to the revenue requirement.

EXHIBIT V-7

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1977 (BASED ON 30% INCREASE OVER 1976)

	Municipalities Demand	Municipalities Energy	Municipalities Total	Large Users Demand From Mun.	Large Users Demand From Dir.	Large Users Energy From Mun.	Large Users Energy From Dir.	Large Users Total	Rural Retail Demand	Rural Retail Energy	Rural Retail Total	Total Cost
Existing Rate Structure and Classes												
Cost – $000's	606,539	515,228	1,121,767	115,913		150,525		266,438	132,715	117,852	250,567	1,638,772
Billed Usage	9,762 MW	60,615 GWh		2,386 MW		16,273 GWh			2,136 MW*	13,865 GWh		
Annual Rate	62.13 $/kW	8.5 M/kWh		49.58 $/kW		9.25 M/kWh			62.13 $/kW	8.5 M/kWh		
Monthly Rate	5.18 $/kW	8.5 M/kWh		4.05 $/kW		9.25 M/kWh			5.18 $/kW	8.5 M/kWh		
Existing Rate Structure and Classes Less Diversity												
Cost – $000's	591,372	515,228	1,106,600	144,542		138,321		282,863	131,457	117,852	249,309	1,638,772
Billed Usage	9,762 MW	60,615 GWh		2,386 MW		16,273 GWh			2,170 MW	13,865 GWh		
Annual Rate	60.58 $/kW	8.5 M/kWh		60.58 $/kW		8.5 M/kWh			60.58 $/kW	8.5 M/kWh		
Monthly Rate	5.05 $/kW	8.5 M/kWh		5.05 $/kW		8.5 M/kWh			5.05 $/kW	8.5 M/kWh		
Existing Rate Structure and Proposed Classes												
Cost – $000's	505,078	432,148	937,226	86,962	144,542	83,018	138,321	452,903	130,790	117,853	248,643	1,638,772
Billed Usage	8,380 MW	50,841 GWh		1,455 MW	2,386 MW	9,774 GWh	16,273 GWh		2,170 MW	13,865 GWh		
Annual Rate	60.27 $/kW	8.5 M/kWh		60.27 $/kW		8.5 M/kWh			60.27 $/kW	8.5 M/kWh		
Monthly Rate	5.02 $/kW	8.5 M/kWh		5.02 $/kW		8.5 M/kWh			5.02 $/kW	8.5 M/kWh		
Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement												
Cost – $000's	336,519	594,311	930,830	58,433	95,811	114,258	190,222	458,724	87,141	162,077	249,218	1,638,772
Billed Usage	8,380 MW	50,841 GWh		1,455 MW	2,386 MW	9,774 GWh	16,273 GWh		2,170 MW	13,865 GWh		
Annual Rate	40.16 $/kW	11.69 M/kWh		40.16 $/kW		11.69 M/kWh			40.16 $/kW	11.69 M/kWh		
Monthly Rate	3.35 $/kW	11.69 M/kWh		3.35 $/kW		11.69 M/kWh			3.35 $/kW	11.69 M/kWh		

Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement

	Municipalities Demand	Municipalities Energy	Municipalities Total	Large Users Demand	Large Users Energy	Large Users Total	Rural Retail Demand	Rural Retail Energy	Rural Retail Total	Total Cost
Cost – Winter $000's	293,168	213,747		129,010	98,089		80,154	56,228		
Cost – Summer $000's	43,897	157,661		21,015	77,607		10,660	43,031		
Cost – Off Peak $000's	–	225,812		–	125,763		–	62,930		
Total $000's	337,065	597,220	934,285	150,025	301,459	451,484	90,814	162,189	253,003	1,638,772
Billed Usage – Winter	8,833 MW	14,751 GWh		3,887 MW	6,772 GWh		2,415 MW	3,882 GWh		
Billed Usage – Summer	7,927 MW	12,699 GWh		3,795 MW	6,251 GWh		1,925 MW	3,446 GWh		
Billed Usage – Off Peak	–	23,385 GWh		–	13,024 GWh		–	6,517 GWh		
Billed Usage – Total	8,380 MW	50,841 GWh		3,841 MW	26,047 GWh		2,170 MW	13,865 GWh		
Monthly Rate – Winter	5.54 $/kW	14.5 M/kWh		5.54 $/kW	14.5 M/kWh		5.54 $/kW	14.5 M/kWh		
Monthly Rate – Summer	.92 $/kW	12.4 M/kWh		.92 $/kW	12.4 M/kWh		.92 $/kW	12.4 M/kWh		
Monthly Rate – Off Peak		9.7 M/kWh			9.7 M/kWh			9.7 M/kWh		

* Share of power district costing load

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EXHIBIT V-7

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1978 (BASED ON 15% INCREASE OVER 1977)

	Municipalities			Large Users					Rural Retail System			Total Cost
	Demand	Energy	Total	Demand From Mun.	Demand From Dir.	Energy From Mun.	Energy From Dir.	Total	Demand	Energy	Total	
Existing Rate Structure and Classes												
Cost - $000's	759,847	605,525	1,365,472	171,491		178,410		349,901	168,626	139,755	308,381	2,023,754
Billed Usage	10,356 MW	63,750 GWh		2,703 MW		18,780 GWh			2,296 MW*	14,711 GWh		
Annual Rate	73.44 $/kW	9.5 M/kWh		58.23 $/kW		10.25 $/kW			73.44 $/kW	9.5 M/kWh		
Monthly Rate	6.12 $/kW	9.5 M/kWh		4.85 $/kW		10.25 $/kW			6.12 $/kW	9.5 M/kWh		
Existing Rate Structure and Classes Less Diversity												
Cost - $000's	739,841	605,625	1,345,466	193,291		178,410		371,701	166,832	139,755	306,587	2,023,754
Billed Usage	10,346 MW	63,750 GWh		2,703 MW		18,780 GWh			2,333 MW	14,711 GWh		
Annual Rate	71.51 $/kW	9.5 M/kWh		71.51 $/kW		9.5 M/kWh			71.51 $/kW	9.5 M/kWh		
Monthly Rate	5.96 $/kW	9.5 M/kWh		5.96 $/kW		9.5 M/kWh			5.96 $/kW	9.5 M/kWh		
Existing Rate Structure and Proposed Classes												
Cost - $000's	624,456	500,393	1,124,849	116,269	193,291	105,232	178,410	593,202	165,948	139,755	305,703	2,023,754
Billed Usage	8,779 MW	52,673 GWh		1,635 MW	2,703 MW	11,077 GWh	18,780 GWh		2,333 MW	14,711 GWh		
Annual Rate	71.13 $/kW	9.5 M/kWh		71.13 $/kW		9.5 M/kWh			71.13 $/kW	9.5 M/kWh		
Monthly Rate	5.93 $/kW	9.5 M/kWh		5.93 $/kW		9.5 M/kWh			5.93 $/kW	9.5 M/kWh		
Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement												
Cost - $000's	411,930	703,174	1,115,104	77,381	126,825	147,872	250,713	602,791	109,470	196,389	305,859	2,023,754
Billed Usage	8,779 MW	52,673 GWh		1,649 MW	2,703 MW	11,077 GWh	18,780 GWh		2,333 MW	14,711 GWh		
Annual Rate	46.92 $/kW	13.35 M/kWh		46.92 $/kW		13.35 M/kWh			46.92 $/kW	13.35 M/kWh		
Monthly Rate	3.91 $/kW	13.35 M/kWh		3.91 $/kW		13.35 M/kWh			3.91 $/kW	13.35 M/kWh		
Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement												
Cost - Winter $000's	359,009	258,483		170,872		130,767			100,761	69,383		
- Summer $000's	53,746	183,333		27,828		99,716			13,390	51,180		
- Off Peak $000's	-	265,337		-		163,994			-	75,955		
Total $000's	412,755	707,153	1,119,908	198,700		394,477		593,177	114,151	196,518	310,669	2,023,754
Billed / Usage - Winter	9,253 MW	15,345 GWh		4,404 MW		7,763 GWh			2,597 MW	4,119 GWh		
- Summer	8,305 MW	13,175 GWh		4,300 MW		7,166 GWh			2,069 MW	3,678 GWh		
- Off Peak	-	24,153 GWh		-		14,928 GWh			-	6,914 GWh		
Total	8,779 MW	52,673 GWh		4,352 MW		29,857 GWh			2,333 MW	14,711 GWh		
Monthly Rate - Winter	6.47 $/kW	16.8 M/kWh		6.47 $/kW		16.8 M/kWh			6.47 $/kW	16.8 M/kWh		
- Summer	1.08 $/kW	13.9 M/kWh		1.08 $/kW		13.9 M/kWh			1.08 $/kW	13.9 M/kWh		
- Off Peak	-	11.0 M/kWh		-		11.0 M/kWh			-	11.0 M/kWh		

* Share of power district costing load

EXHIBIT V-7

Page 3 of 3

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1979 (BASED ON 10% INCREASE OVER 1978)

	Municipalities			Large Users					Rural Retail System			Total Cost
	Demand	Energy	Total	Demand From Mun.	From Dir.	Energy From Mun.	From Dir.	Total	Demand	Energy	Total	

Existing Rate Structure and Classes

Cost – $000's	871,517	688,422	1,559,939	207,324		215,187		422,511	197,271	161,815	359,086	2,341,536
Billed Usage	10,837 MW	65,564 GWh		2,984 MW		20,494 GWh			2,453 MW*	15,411 GWh		
Annual Rate	80.42 $/kW	10.5 M/kWh		64.33 $/kW		11.25 M/kWh			80.42 $/kW	10.5 M/kWh		
Monthly Rate	6.70 $/kW	10.5 M/kWh		5.36 $/kW		11.25 M/kWh			6.70 $/kW	10.5 M/kWh		

Existing Rate Structure and Classes Less Diversity

Cost – $000's	847,691	688,422	1,536,113	233,414		215,187		448,601	195,007	161,815	356,822	2,341,536
Billed Usage	10,837 MW	65,564 GWh		2,984 MW		20,494 GWh			2,493 MW	15,411 GWh		
Annual Rate	78.22 $/kW	10.5 M/kWh		78.22 $/kW		10.5 M/kWh			78.22 $/kW	10.5 M/kWh		
Monthly Rate	6.52 $/kW	10.5 M/kWh		6.52 $/kW		10.5 M/kWh			6.52 M/kWh	10.5 M/kWh		

Existing Rate Structure and Proposed Classes

Cost – $000's	708,493	560,049	1,268,542	141,569	128,373	232,125	215,187	717,254	193,925	161,815	355,740	2,341,536
Billed Usage	9,108 MW	53,338 GWh		1,820 MW	12,226 GWh	2,984 MW	20,494 GWh		2,493 MW	15,411 GWh		
Annual Rate	77.79 $/kW	10.5 M/kWh		77.79 $/kW		10.5 M/kWh			77.79 $/kW	10.5 M/kWh		
Monthly Rate	6.48 $/kW	10.5 M/kWh		6.48 $/kW		10.5 M/kWh			6.48 $/kW	10.5 M/kWh		

Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement

Cost – $000's	486,698	770,044	1,256,742	97,243	159,243	295,933	176,447	729,088	133,217	222,489	355,706	2,341,536
Billed Usage	9,108 MW	53,338 GWh		1,820 MW	12,226 GWh	2,984 MW	20,494 GWh		2,493 MW	15,411 GWh		
Annual Rate	53.44 $/kW	14.44 M/kWh		53.44 $/kW		14.44 M/kWh			53.44 $/kW	14.44 M/kWh		
Monthly Rate	4.45 $/kW	14.44 M/kWh		4.45 $/kW		14.44 M/kWh			4.45 $/kW	14.44 M/kWh		

Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement

Cost – Winter $000's	424,314	280,915		214,897		153,296			122,653	77,757		
– Summer $000's	63,492	200,578		34,974		117,926			16,293	57,859		
– Off Peak $000's	–	293,030		–		196,539			–	87,013		
Total $000's	487,806	774,523	1,262,329	249,871		467,761		717,632	138,946	222,629	361,575	2,341,536
Billed – Winter	9,600 MW	15,589 GWh		4,862 MW		8,507 GWh			2,775 MW	4,315 GWh		
Usage – Summer	8,616 MW	13,357 GWh		4,746 MW		7,853 GWh			2,211 MW	3,853 GWh		
– Off Peak	–	24,392 GWh		–		16,360 GWh			–	7,243 GWh		
Total	9,108 MW	53,338 GWh		4,804 MW		32,720 GWh			2,493 MW	15,411 GWh		
Monthly Rate – Winter	7.37 $/kW	18.0 M/kWh		7.37 $/kW		18.0 M/kWh			7.37 $/kW	18.0 M/kWh		
– Summer	1.23 $/kW	15.0 M/kWh		1.23 $/kW		15.0 M/kWh			1.23 $/kWh	15.0 M/kWh		
– Off Peak	–	12.0 M/kWh		–		12.0 M/kWh			–	12.0 M/kWh		

* Share of power district costing load

VI. PROPOSED PRICE STRUCTURES AND ILLUSTRATIVE PRICE SCHEDULES AT THE RETAIL LEVEL

In order to meet the efficiency objective, the marginal price to the end user must be based on marginal production costs. This was the guiding principle in designing the retail price schedules. While the distributing retail utility would be charged on the basis of prorated unit costs, the customers of the utility would be priced on the basis of marginal production costs. In other words, the marginal costs at the bulk level would be 'flowed through' the municipal utility to the end customer, ensuring that all end customers receive the proper price signal.

A single-rate structure would apply to customers that comprise the retailing utility's load, net of large users. The rate structure would be known as the general rate and would consist of a charge with the following three parts:

1. Customer Charge

The customer charge would be based on the marginal cost of adding a customer to the municipal system. This cost can be estimated from data on such things as customer accounting, customer services, meter operation, direct services, transformer maintenance expense, return on meters, and transformers, and those distribution-system costs which do not vary with output. If any surplus revenue is generated in the municipality, attributable to the demand and energy component it would be applied as a credit against the customer charge.

This flow-through method may add somewhat to the present problems arising from forecast revenues not matching actual revenues. If the municipal utilities were priced on the basis of the large-user pricing rule, this problem would not arise.

While customer costs are a function of several factors, there are two major cost-causing variables which should be singled out: density of customers and type of customers.

Customer density affects such costs as those of the distribution system and associated maintenance and operations. The type of customer may affect the type of plant installed. For example, an area which is heavily commercial may require underground cable rather than overhead lines. These cost differentials should be reflected in the use of sub-classes of customers. Employing these cost differentials, the following six customer classes as presently is the case be employed in the rural retail system of Ontario Hydro.

Group One: R1

This customer group would represent high-density residential areas of at least 100 customers, with a minimum of 25 customers per mile.

Group Two: R2, F2-1

This would be the normal-density residential and single-phase farm customer group of about 10 customers per mile.

Group Three: R3

This would be a high density group of residential customers with intermittent occupancy, in high-cost construction areas.

Group Four: R4

This would be a normal density group of customers with intermittent occupancy higher-cost construction areas.

Group Five: G, F2-3

This group would be composed of general class and three phase farms, served at distribution voltage levels. Higher costs result from low density, larger size services and, in the case of demand billed services, monthly, rather than quarterly, meter readings.

Group Six: T, G9

This group would be composed of large three-phase general customers served at sub-transmission voltage levels with higher installation costs.

The general class is subdivided between customers supplied at distribution and sub-transmission voltage levels to reflect the fact that sub-transmission voltage customers do not contribute to the cost of transformation to distribution voltage levels, nor to the cost of the distribution voltage system.

2. Demand Charge

All customer loads greater than 50 kilowatts would face a demand charge. This demand charge would reflect the marginal costs of the generation and high-voltage common facilities. In addition, it would reflect the marginal cost of sub-transmission, and distribution facilities dependent on the transformation and voltage conditions of supply to the customer. The demand charge would be based on the customer's average non-coincident peak demand.

3. Energy Charge

An energy charge would exist for the first 10,000 kilowatt-hours of use per month, reflecting the marginal energy costs of generation, and marginal losses of the delivery system. The relevant marginal demand costs associated with the first 50 kilowatts of load at 200 hour use per month would be folded into the marginal energy costs, adjusted by the coincident load factor of all customers whose total use is less than 10,000 kilowatt-hours per month. This would meet the consensus criterion of continuity in a rate, schedule that moves from a pure energy rate to a two part rate. A second block of 990,000 kilowatt-hours per month would reflect the marginal energy costs of generation added to marginal losses as appropriate, at the point of delivery. The end rate would be used to provide co-ordination with the large user group. A cost-benefit analysis for residential time-of-use rates is included in Appendix Seven of this volume. The costs of new metering appear to outweigh the expected benefits from time-of-use rates. However, the results are close and the issue is discussed at greater length in the next section.

A. DETAILED DESCRIPTION OF PRICING METHODOLOGY

The following is a description of the proposed methodology for setting marginal cost-based rates for the rural retail system for the years 1977 to 1979. It should be noted that these rate structures are purely illustrative, pending further analysis of the class revenue requirement, and the development of load data.

The detailed methodology for determining the demand and energy rates can best be illustrated by use of formulae. These are the five basic steps involved in the proposed pricing methodology:

1. Allocation of common bulk power marginal costs,
2. Allocation of non-common marginal costs,
3. Allocation of distribution system costs,
4. Determining the resulting marginal rates, and
5. Departures from the marginal rates.

B. ALLOCATION OF COMMON BULK POWER MARGINAL COSTS

The projected common bulk power marginal capacity costs would be converted to billing-load unit rates. These unit rates would then be multiplied by the forecast retail system billing-loads, including those of local systems, in order to arrive at the

total marginal capacity costs, for each of the three years under study. In order to determine the total marginal energy costs, the projected marginal energy unit costs would be multiplied by the forecast delivered energy.

The following symbols and definitions will be used:

1. $D = Total marginal capacity costs of the bulk power system attributable to the retail system. This sum is found by multiplying the marginal unit bulk capacity cost per kW by total retail system billing kW.

2. $E = Total marginal energy costs of the retail system. This sum is found by multiplying the marginal unit bulk energy cost per kWh by total delivered kWh to the retail system.

3. $F = Estimated revenue from fixed-charge accounts, street lighting, sentinel lights and flat-rate water heaters.

4. kWh_o = Total estimated retail energy sales. It is important to note that kWh_o is less than forecast delivered energy, because of losses.

5. kWh_1 = Total energy sales for all customers up to 10,000 kWh per month, that is, up to 50 kW and 200 hours use, excluding the kilowatt-hours related to $F.

6. kW_{NC} = Total estimated non-coincident billed kW over 50 kW.

7. L = Adjustment for load factor variation between customers over and under 10,000 kWh. It is defined as the inverse ratio of their respective average co-incident load factors.

At this point it is necessary to divide the total marginal capacity costs, $D, into the following components:

1. $c¢ = $D \cdot kWh_o$ = Demand component expressed in cents per kWh.

2. $D_1 = c \times kWh_1XL$ = Total marginal capacity costs applicable to all energy sales up to 10,000 kWh per month.

3. $D_2 = $D-$D_1$ = Total marginal capacity costs applicable to all billed kW, plus the fixed-charge accounts.

4. $D_3 = $D_2 - F = Total marginal capacity costs applicable to all billed kW.

It is possible now to develop both the common demand and common energy rates based on marginal costs.

1. $d^1 = D_3 / kW_{NC} = Common marginal demand rate per kW.

2. $e¢ = $E \ kWh_o$ = basic marginal energy rate per kWh. This calculation accounts for distribution system losses because kWh_o is less than forecast delivered energy.

3. $e^1¢ = e^c + ($D_1/kWh_1$ = common marginal demand / energy rate per kWh.

(See Appendix Two for a full discussion of the rationale for folding the demand charge into the energy charge.)

C. ALLOCATION OF NON-COMMON MARGINAL COSTS

The same procedure as outlined above would be repeated to determine non-common function unit demand and energy rates. The figures would be added to the respective common function rates in order to develop an intermediate demand rate of d per kW, and an energy rate of e cents per kWh.

D. ALLOCATION OF DISTRIBUTION SYSTEM MARGINAL COSTS

Distribution system marginal costs are not applicable to subtransmission voltage customers. Therefore, the projected billing statistics of these customers would be subtracted from kWh_o, kWh_1 and kW_{NC}, before repeating the above process to determine the distribution system marginal unit demand and energy rates. These unit rates would be added respectively to d and e cents above, in order to arrive at the final marginal demand rate of d per kW, and the marginal energy rate of e cents per kWh, applicable to all customers supplied at distribution voltage levels.

E. THE RESULTING RATES BASED ON MARGINAL COSTS

The marginal cost-based rates resulting from the above procedures would be as shown in the accompanying table

```
Non-Demand Billed Accounts (Under 50 kW)

e''' per kWh for all kilowatt-hours

Demand Billed Accounts (Over 50 kW)

Demand:

0-50 kW               - no charge
Balance               - $d''' per kW per month
Subtransmission
 voltage allowance    - $(d''' - d'') per kW per month

Energy:

First 10,000 kWh/mo. - e''' ¢ per kWh
Next 990,000 kWh/mo. - e¢ per kWh
Balance              - average rate per kWh
                       for large users
```

F. DEPARTURES FROM THE MARGINAL COST-BASED RATES

Marginal cost-based rates were calculated for the three years 1977, 1978, and 1979 using the above procedures. These rates were then applied to the projected class-billing statistics to arrive at the total marginal cost revenue from demand and energy sales. The revenues generated by the marginal cost-based rates were then compared with the estimated revenue requirement for the rural retail system.

Surplus revenues would be generated from rates based on marginal costs for 1977, 1978, and 1979 using the illustrative cost figures. Hence, in all three years the customer charge would be reduced, because of the surplus revenues. For 1977 and 1978 it was necessary to roll back both the demand and energy rates as well, because of the magnitude of the surplus. Alternatively, the customer charge could have been reduced by a greater amount in 1977 and 1978, reducing it in some cases close to zero. This was not done in the interest of providing greater continuity in the customer charge, and of keeping it more in line with avoidable customer costs.

Under marginal-cost pricing, customer-related costs include rate-base and expense items, which relate to the number of customers. Typically, these would include fixed-cost components of the general distribution system which do not vary with demand and energy, plus the avoidable customer costs such as service-drops and local connection facilities, metering equipment, meter reading, billing and collecting, and accounting-costs

Exhibit VI-1 shows that the estimated avoidable customer costs alone, exclusive of the fixed cost component of the general distribution system, for an average year-round residential customer, for 1977, is $2.67 per month. For larger demand-billed and three-phase customers, the carrying charges on service drop, and metering equipment increases substantially, particularly where metering cabinets, current and potential transformers are required. In addition, the meter-reading costs would increase to about $1.10 per month, because of monthly meter reading as opposed to quarterly reading for residential services.

EXHIBIT VI-1

1977 Estimated Avoidable Customer Cost
For an Average Year-Round Residential Customer

	$/Month
Carrying charges on 70 feet of service drop, connections, etc., plus a 200-amp 3-wire meter installed	0.85
Meter reading costs (4 per year)	.37
Billing costs	.70
Mailing costs	.25
Clerical costs	.25
Collection costs	.25
Total	2.67

Because of the lack of data by customer class, marginal customer costs were not established. Appendix IV of this volume discusses methods for the future establishment of customer costs and treatment of the surplus revenues generated by the demand and energy charge.

Given the revenues generated by the demand and energy components of the bill, and the estimated avoidable customer costs, the following procedure was adopted. First, the customer charge was increased to a reasonable minimum level for each of the customer classes, and new total class revenues estimated. Second, the residual surplus revenues from the demand and energy components was eliminated by rolling back the bulk power common marginal cost components for demand and energy.

For 1977, the common demand and energy components were rolled back 15 per cent and 3 per cent respectively, in 1978 by 8 per cent and 2 per cent respectively, and in 1979 no fold-back was required. The rationale for rolling back the demand component by a greater percentage than the energy component was two-fold. First, while no empirical study exists, informed opinion is that customers are more price-sensitive to energy than to demand, it is necessary that the energy rate should come as close as possible to the marginal energy cost in order that the short-run fuel costs are met for any change in load. Second, existing excess system capacity implies that marginal curtailment costs are below marginal capacity costs. As a result, the demand rate should be lowered to more closely reflect the marginal curtailment costs if the system is in a non-optimal, excess-capacity situation.

Care had to be taken to avoid a 'ballooning' effect in the rate-structure design. Ballooning effects arise from the manner in

which demand and energy costs are combined in a pure energy rate for non-demand-billed customers. Ideally, demand and energy costs should be combined on the basis of the relevant load factor of customers under 50 kW.[3] It has been past practice to use a load factor of 200 hours use for this purpose (see Appendix II). This rationale is used as well to establish the size of the first energy block (i.e. 50 kW at 200 hours use equals 10,000 kWh), in order to complement the folding in of the demand costs at a given load factor. If the block size does not match the relevant hours' use, then 'ballooning' occurs.

A ballooning feature has always existed to some extent in rate structures in the past. However, it has been confined largely to customers exceeding 50 kW at a load factor of less than 200 hours per month. This ballooning is inherent in the rate configuration itself. It would be largely avoided with a time-of-use rate form.

Because of the lack of appropriate load and cost data, some assumptions were required in the development of the illustrative retail rates. The marginal-costs based rates for 1977, 1978, and 1979, are illustrated in Exhibit VI-2.

EXHIBIT VI-2

Summary of the Illustrative Marginal Cost-Based Rates for the Rural Retail System

Monthly Customer Charge

Class	1977	1978	1979
R1	$ 3.50	$ 4.00	$ 4.50
R2 & F2-1	4.00	4.50	5.00
R3	6.00	6.75	7.50
R4	6.75	7.50	8.25
G & F2-3	8.00	8.50	9.00
T & G9 Special	15.00	18.00	20.00

Above Customer Charges plus the following Monthly Rates:

Kilowatt Charge

	1977	1978	1979
First 50 kW	N/C		
Balance-per kW	$3.30	$3.80	$4.60
Subtransmission voltage allowance	0.35	0.40	0.50
3-phase transfrmr allowance			
. up to 49.9 kV	0.25	0.25	0.25
. 50 kV and above	0.50	0.50	0.50

Energy Charges	¢/kWh	¢/kWh	¢/kWh
1st 10,000 kWh	2.94	3.29	3.65
Next 990,000 kWh	1.58	1.71	1.80
All additional kWh	1.15	1.32	1.43

When these rates were applied to the billing statistics for the eight municipal utilities selected for the study, they resulted in revenues exceeding the estimated revenue requirement in each case. That is, the rates would result in negative customer charges. Thus, it was again necessary to fold back on all demand and energy rates. For the year 1977, for example, both demand and energy rates were folded back by 12 per cent for

[3]It should be noted that averaging of the time-differentiated marginal costs is inevitable here without time-of-use rates.

Acton, Belleville, Mount Brydges and Ottawa, and by 5 per cent for Elora, North York, Oakville and Vaughan Township. The resulting illustrative rates for the residential and general classes in these municipalities are shown in Exhibit VI-3.

The effect of the illustrative rate proposals on class revenues for 1977, 1978, and 1979 for the Rural retail system and the eight selected municipal utilities is shown in Exhibit VI-4.

G. COMPARISON WITH THE EXISTING RATE STRUCTURE

Appendix I shows illustrative rates and rate structures that would apply for the years 1977, 1978, and 1979 under the present pricing methodology.

Under the proposed rate schedule, all uses would be priced at the same energy rate based on the marginal cost of electricity. There would be no special rates for different types of electricity use, such as for water heaters.

Under the existing rate schedules there exists a lack of uniformity in the municipal utilities' rates, although the lack of uniformity is partly a result of impact problems in raising end rates. Under the proposals presented here, these rate differentials will be reduced. The energy charge would tend to be more uniform. It is possible that no more than three or four rate structures would suffice for all utilities throughout the province. However, differentials would remain in the customer charge due to local cost considerations which exist in each electric utility. These reflect such factors as the utility's policy on contributed capital, debt equity relationship, type of service rendered, and customer density. In relative terms, marginal-cost based rates tend to increase the cost of electricity for larger users, as compared to the approach of declining block-rates based on average costs. For example, the residential rates illustrated for the rural retail system decrease the monthly bill for all customers consuming very roughly less than average. Conversely, customers with above average consumption would receive higher bills, increasing proportionately over the traditional design with increasing consumption, to a maximum in the order of 10 per cent higher. Similarly, in the general class, all customers over 50 kW would experience a higher power bill, up as much as approximately 15 per cent, depending on load and load factor.

The impact of converting to marginal-cost rates would not be fully realized in any one year, since it is recommended to phase in these charges over a long-enough period to minimize undue hardship on the customers adversely affected. Nevertheless, the intent of marginal-cost rates to increase the cost of electricity for large consumers will be quite clear, and therefore the incentive to conserve electrical energy will also be clear. Although less than 36 per cent of the customers on the rural retail system would experience increases in their power bills, these customers purchase more than 47 per cent of all the energy sold by this utility, a fact which offers a significant market potential for energy conservation.

Exhibit VI-5 shows, in both tabular and graphic forms, how the illustrative rates based on marginal-cost pricing would affect rural residential and general-class customer bills compared with bills based on rates set under the present pricing methodology. As can be seen, the low user pays less under the marginal-cost pricing proposal while the large user pays more. In addition, all users have a greater incentive to conserve because of the higher cost of consuming one more kilowatt, and the associated greater saving of consuming one less kilowatt-hour.

Exhibit VI-3

SUMMARY OF ILLUSTRATIVE MARGINAL COST-BASED RATES - MUNICIPAL UTILITIES

MONTHLY CUSTOMER CHARGES

	1977		1978		1979	
	Residential	General	Residential	General	Residential	General
(1) Acton	1.75	3.75	2.50	5.70	2.95	6.00
(2) Belleville	.75	1.75	1.50	3.00	.30	1.00
(3) Elora	.65	1.25	1.00	1.65	3.00	6.60
(4) Mount Brydges	.30	.90	.70	1.50	.20	.75
(5) North York	1.95	4.50	1.85	4.75	2.00	5.85
(6) Oakville	2.40	5.35	2.85	6.75	4.25	7.10
(7) Ottawa	2.25	5.50	4.00	8.45	1.70	5.00
(8) Vaughan Twp.	.90	2.60	3.75	6.75	1.75	5.00

Above Customer Charges plus the following Monthly Rates

Utilities	(1), (2), (4), (7)	(1), (2), (4), (7), (8)	(1)(2)(3)(4)(7)(8)
Demand 0-50 kW	N/C	N/C	N/C
over 50 kW-per kW	$2.90	$3.25	$4.05
sub-transmission allowance	$0.30	$0.35	$0.45
Energy			
1st 10,000 kWh/Mo-¢/kWh	2.59	2.80	3.21
Next 990,000 kWh/MO-¢/kWh	1.40	1.46	1.58
All additional kWh/Mo-¢/kWh	1.15	1.32	1.43

Utilities	(3), (5), (6), (8)	(3), (5), (6)	(5), (6)
Demand 0-50 kW	N/C	N/C	N/C
over 50 kW-per kW	$3.10	$3.55	$4.25
sub-transmission allowance	$0.30	$0.35	$0.45
Energy			
1st 10,000 kWh/Mo	2.79	3.06	3.36
Next 990,000 kWh/Mo	1.50	1.59	1.65
All additional kWh/Mo	1.15	1.32	1.43
3-Phase transformation allowance			
up to 49.9 kV	$0.25/kW	$0.25/kW	$0.25/kW
50 kV and above	$0.50/kW	$0.50/kW	$0.50/kW

Exhibit VI-4

EFFECT OF PROPOSALS ON RETAIL CLASS REVENUES

RURAL RETAIL SYSTEM

$'000

	REVENUE BASED ON EXISTING PRICING METHOD	REVENUE BASED ON PROPOSED PRICING METHOD	% CHANGE
1977			
R1	97,683	97,535	-0.15
R2 + F1	147,916	146,335	-1.08
R3	11,852	11,031	-7.44
R4	16,559	15,972	-3.68
G + F2 - 3	88,413	89,009	+0.67
T + G Special	38,479	41,350	+7.46
1978			
R1	118,848	116,834	-1.72
R2 + F1	176,019	172,780	-1.87
R3	14,168	13,095	-8.19
R4	19,620	18,746	-4.66
G + F2 - 3	101,052	104,255	+3.17
T + G Special	45,704	49,848	+9.07
1979			
R1	142,472	138,602	-2.79
R2 + F1	206,414	201,608	-2.38
R3	16,698	15,397	-8.45
R4	23,090	21,766	-6.08
G + F2 - 3	115,884	121,181	+4.57
T + G Special	53,924	59,998	+11.26

Exhibit VI-4

page 2

EFFECT OF PROPOSALS ON RETAIL CLASS REVENUES - SELECTED MUNICIPAL UTILITIES

	1977			1978			1979		
	Existing Method	Proposed Method	% Change	Existing Method	Proposed Method	% Change	Existing Method	Proposed Method	% Change
Residential									
Acton	477,907	507,922	+6.28	520,204	563,561	+8.33	631,100	648,077	+2.69
Belleville	2,488,126	2,657,752	+6.82	2,695,018	2,962,317	+9.92	3,034,202	3,211,005	+5.83
Elora	208,613	207,094	-0.07	229,284	229,561	+0.12	256,357	256,539	+0.07
Mount Brydges	87,859	90,952	+3.52	96,836	100,233	+3.51	109,571	111,852	+2.08
North York	29,625,457	29,548,046	-0.03	32,998,712	31,979,459	-3.19	36,145,057	35,068,112	-3.07
Oakville	5,523,261	5,642,114	+2.15	6,167,001	6,235,456	+1.11	7,040,753	7,090,302	+0.70
Ottawa	21,912,859	24,622,489	+12.37	25,172,823	28,339,720	+12.58	28,367,938	29,321,643	+3.36
Vaughan Twp.	1,983,105	1,978,735	-0.02	2,111,318	2,224,068	+5.34	2,297,414	2,336,449	+1.70
General									
Acton	646,622	616,729	-4.85	712,488	669,129	-6.48	780,942	764,123	-2.20
Belleville	4,067,393	3,898,783	-4.32	4,492,302	4,224,600	-6.34	4,936,690	4,760,608	-3.70
Elora	163,247	164,766	+0.09	181,530	181,265	-0.15	194,284	194,110	-0.09
Mount Brydges	46,172	43,210	-6.85	50,481	47,059	-7.27	55,349	53,055	-4.32
North York	53,050,298	53,154,765	+0.20	57,125,091	58,141,717	+1.78	62,698,045	63,771,469	+1.71
Oakville	6,000,698	5,881,788	-2.02	6,551,749	6,482,457	-1.07	7,129,292	7,078,829	-0.71
Ottawa	45,452,875	42,758,994	-6.30	49,558,978	46,394,478	-6.82	53,069,339	52,138,129	-1.79
Vaughan Twp.	2,602,998	2,607,096	+0.16	2,827,014	2,714,716	-4.14	3,089,629	3,049,363	-1.32

Exhibit VI-5

page 1

EFFECT OF PROPOSALS ON INDIVIDUAL RETAIL CUSTOMER BILLS

RURAL

RESIDENTIAL CLASS

1R1 (High Density)

kWh/Mo	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
250	15.50	10.85	-30.00	17.75	12.23	-31.10	20.25	13.63	-32.69
750	27.65	25.55	-7.59	31.25	28.68	-8.22	35.00	31.88	-8.91
1,000	33.53	32.90	-1.88	37.88	36.91	-2.56	42.38	41.01	-3.23
2,000	57.03	62.30	+9.24	64.38	69.81	+8.43	71.88	77.51	+7.83

1R2 (Standard Density)

kWh/Mo	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
250	16.88	11.35	-32.76	19.25	12.73	-33.87	21.75	14.13	-35.03
750	29.13	26.05	-10.57	32.75	29.18	-10.90	36.50	32.38	-11.29
1,000	35.01	33.40	-4.60	39.38	37.41	-5.00	43.88	41.51	-5.40
2,000	58.51	62.80	+7.33	65.88	70.31	+6.72	73.38	78.01	+6.31

GENERAL CLASS

Distribution Voltage Level

75 kW

	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
7,500	308.38	311.00	+0.85	321.25	350.25	+9.01	351.38	397.75	+13.20
15,000	447.13	463.50	+3.66	466.00	518.00	+11.16	520.13	579.00	+11.32
30,000	649.63	700.50	+7.83	691.00	774.50	+12.08	775.13	849.00	+9.53

300 kW

	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
60,000	1765.63	1917.00	+8.57	1876.00	2142.50	+14.21	2027.63	2424.00	+19.55
90,000	2170.63	2391.00	+10.15	2326.00	2655.50	+14.17	2537.63	2964.00	+16.80
120,000	2575.63	2865.00	+11.23	2776.00	3168.50	+14.14	3047.63	3504.00	-14.97

Sub-Transmission Voltage Level

1,000 kW (Hydro-owned transformers)

	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
200,000	5904.73	6096.00	+3.24	6216.00	6808.00	+9.52	6717.63	7675.00	+14.25
400,000	8604.73	9256.00	+7.57	9216.00	10226.00	+10.96	10117.63	11275.00	+11.44

4,000 kW (customer-owned transformers)

	1977 Existing	Proposed	% Change	1978 Existing	Proposed	% Change	1979 Existing	Proposed	% Change
800,000	22184.63	23426.00	+5.60	23816.00	26266.00	+10.29	25817.63	29775.00	+15.32
1600,000	31864.63	33486.00	+5.09	35816.00	37606.00	+5.00	39417.63	41175.00	+4.46
2000,000	36704.63	38086.00	+3.76	41816.00	42886.00	+2.56	46217.63	48375.00	+4.67

Rate impact constraints were not applied to the marginal cost rates in order that the total bill differences would be noted.

Exhibit VI-5   Page 2

1977 RATES

Schedule 1R1

$0.75 + 5.9¢/kwh - 1st 250 kW
+ 2.45¢/kWh - next 500 kWh
+ 2.35¢/kWh - balance

Minimum bill - $4.00/month

Schedule R1

$3.50 + 2.94¢/kWh - all kWh

Schedule 1R1

Schedule R1

Schedule R1

kilowatt-hours per month

TOTAL MONTHLY BILL $

0   200   400   600   800   1000   1200   1400   1600   1800   2000   2200   2400

0   10.00   20.00   30.00   40.00   50.00   60.00   70.00   80.00   90.00

Exhibit VI-5   Page 3

1977 RATES

Schedule PR1-ER1

$0.75 + 5.9¢/kWh - 1st 250 kWh
+ 2.25¢/kWh - next 500 kWh
+ 2.43¢/kWh - next 500 kWh
+ 2.35¢/kWh - balance
Minimum bill - $4.00 per month

Schedule R1

$3.50 + 2.94¢/kWh - all kWh

Schedule PR1-ER1

Schedule R1

kilowatt-hours per month

200   400   600   800   1000   1200   1400   1600   1800   2000   2200   2400

TOTAL MONTHLY BILL $

10.00   20.00   30.00   40.00   50.00   60.00   70.00   80.00   90.00

Exhibit VI-5   Page 4

1979 RATES

Schedule 1R1, PR1, ER1

$2.25 + 7.2¢/kWh - 1st 250 kWh
        + 2.95¢/kWh - balance
Minimum bill - $4.00/month

Schedule R1
$4.50 + 3.65¢/kWh - all kWh

Schedule 1R1, PR1, ER1

Schedule R1

TOTAL MONTHLY BILL $

kilowatt-hours per month

Exhibit VI-5   Page 5

1977 RATES

Schedule 1R3

$63.00 + 5.25¢/kWh - 1st 1800 kWh
      + 2.90¢/kWh - next 1200 kWh
      + 2.33¢/kWh - next 6000 kWh
      + 2.35¢/kWh - balance

Schedule R3

$72.00 + 2.94¢/kWh - all kWh

Schedule 1R3

Schedule R3

TOTAL ANNUAL BILL $

kilowatt-hours per year

Exhibit VI-5   Page 6

1979 RATES

Schedule 1R3

$69.70 + 6.5¢/kWh - 1st 3,000 kWh
     + 2.6¢/kWh - next 6,000 kWh
     + 2.95¢/kWh - balance

Schedule R3

$90.00 + 5.65¢/kWh - all kWh

kilowatt-hours per month

TOTAL ANNUAL BILL, $

Schedule 1R3

Schedule R3

Exhibit VI-5   Page 7

1977 RATES

Schedule 1G2-11

$0.75 + 8.4¢/kWh - 1st 250 kWh
      + 2.85¢/kWh - next 9,750 kWh
      + 1.35¢/kWh - balance

Schedule G

$8.00 + 2.94¢/kWh - all kWh

kilowatt-hours per month

TOTAL MONTHLY BILL $

Exhibit VI-5   Page 8

1979 RATES

Schedule 1G2-11

$3.00 + 9.2¢/kWh - 1st 250 kWh
      + 3.35¢/kWh - next 9,750 kWh
      + 1.70¢/kWh - balance
Minimum monthly bill - $5.00

Schedule G

$9.00 + 3.65¢/kWh - 1st 10,000 kWh
      + 1.80¢/kWh - balance

kilowatt-hours per month

TOTAL MONTHLY BILL, $

Exhibit VI-5   Page 9

1977 RATES

Schedule 1G2-33

kW - 1st 50 - N/C
   - balance - $3.20/kW

Energy $0.75 + 8.4¢/kWh - first 250 kWh
              + 2.85¢/kWh - next 9,750 kWh
              + 1.35¢/kWh - next 490,000 kWh

Schedule G

kW - 1st 50 - N/C
   - balance - $3.30/kW

Energy $8.00 + 2.94¢/kWh - 1st 10,000 kWh
              + 1.58¢/kWh - next 990,000 kWh

Schedule G - 300 kW

Schedule 1G2-33 - 300 kW

Schedule G - 200 kW

Schedule 1G2-33 - 200 kW

TOTAL MONTHLY BILL $

kilowatt-hours per month

40

Exhibit VI-5   Page 10

1979 RATES

Schedule 1G2-33

kW - 1st 50 kW - N/C
   - balance - $3.20/kW

Energy $3.00 + 9.2¢/kWh - 1st 250 kWh
         + 3.35¢/kWh - next 9,750 kWh
         + 1.70¢/kWh - next 1,990,000
         +1.125¢/kWh - balance

Schedule G

kW - 1st 50 kW - N/C
   - balance - $4.60/kW

Energy $9.00 + 3.65¢/kWh - 1st 10,000 kWh
         + 1.80¢/kWh - next 990,000 kWh
         + 1.43¢/kWh - balance

Schedule G - 200 kW

Schedule 1G2-33 - 200 kW

kilowatt-hours per month

TOTAL MONTHLY BILL $

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Exhibit VI-5

Illustration

1977 General Rates (Schedule G)
0-50 kW - N/C
over 50 kW - $3.30/kW
sub-transmission allowance - $0.35/kW
1st 10,000 kWh/Mo - 2.94¢/kWh
Next 990,000 kW/Mo - 1.58¢/kWh
Balance - 1.15¢/kWh
Customer Charge - $8.00/Mo

Schedule 1G2-3

0-50 kW - N/C
over 50 kW - $3.20/kW

75¢ + 1st 250 kWh - 8.4¢/kWh
Next 9,750 kWh - 2.85¢/kWh
Next 490,000 kWh - 1.35¢/kWh
Next 1,500,000 kWh - 1.21¢/kWh
Balance - .9¢/kWh

Schedule 1G2-3

Schedule G

200 hrs use (27.45 LF) (Schedule G)
200 hrs use (Schedule 1G2-3)
300 hrs use (41.0% LF) (Schedule G)
300 hrs use (Schedule 1G2-3)
hrs use (100% LF) (Schedule G)
730 hrs use (Schedule 1G2-3)

300 kW
200 kW
75 kW
50 kW
730

Monthly Consumption - kWh

Average Rate - ¢/kWh

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Exhibit VI-5 Page 12

1977 GENERAL RATES

500 hrs use marginal

500 hrs use FDC

300 hrs use marginal

300 hrs use FDC

200 hrs use marginal

200 hrs use FDC

100 hrs use marginal

100 hrs use FDC

LOAD IN kW

100 200 300 400 500 600 700 800 900 1000

AVERAGE MONTHLY BILL $/kW

200 400 600 800 1000 1200 1400

Exhibit VI-5   Page 13

1979 GENERAL RATES

500 hrs use marginal
500 hrs use FDC
300 hrs use marginal
300 hrs use FDC
200 hrs use marginal
200 hrs use FDC
100 hrs use marginal
100 hrs use FDC

AVERAGE MONTHLY BILL - $/kW

Load in kW

VII. OTHER RATE ISSUES

There are several additional rate issues which came under scrutiny in the study. The two most important issues were bulk versus individual metering, and residential time-of-day metering. Both of these issues were subjected to cost-benefit analysis. In addition, there were three other issues which are affected by the study: the minimum bill practice, flat-rate water heaters, and special rates. All of these areas are discussed below.

A. BULK METERING VERSUS INDIVIDUAL METERING

Bulk metering is the use of a single meter to measure the electrical consumption of an entire building, rather than individual meters for each unit. The practice of bulk metering of electric service to apartments is usually justified by the utility on the grounds of reduced operating and administrative costs. The requirement for only one meter, one reading, and one bill for the sale of a large quantity of electricity, often results in substantial savings. These savings become more pronounced the greater the number of contained dwelling units in a building that would otherwise be serviced through individual metering.

The concept of bulk metering has had elements of economic attraction for all participants. For the utility, installation costs as well as meter-reading, billing, and collecting costs are reduced under bulk metering. For the landlord, the prevailing block-rate structure for utility services provides him with the opportunity of purchasing the same amount of electricity as would be consumed by all his tenants, at a lower price by acting as a single customer. This enables the landlord to include electrical service as part of the rental package and attract potential tenants with the all-utilities-included marketing scheme. Under these circumstances landlords may pass on some or all of the savings in electricity costs as reduced rental payments. Hence, the tenant has the attraction of the added convenience of one monthly payment for rent and utility service.

On the surface it appears that the practice of bulk metering benefits everyone. However, when individual tenants do not have regular feedback and lack economic incentive to conserve electricity, their consumption may increase. With the recent emphasis on energy conservation, it is important to determine the extent of this increased consumption.

Several independent studies have shown that residents of bulk-metered apartments tend to use more electricity than residents of individually-metered apartments. Findings from an American study carried out by the Mid-West Research Institute for the Federal Energy Administration showed that the ratio of consumption by bulk-metered residents to that of individually-metered residents ranged from 108 per cent to 269 per cent, averaging 134 per cent. Within Ontario Hydro, a more modest study of the same type indicated that bulk-metered apartments, as a group, consumed about 39 per cent more electricity than comparable apartments that were metered individually. On average, the additional consumption amounted to 1,443 kilowatt-hours per suite for 1974.

On the basis of the above findings, it has been suggested that action should be taken to reverse the movement to bulk metering as a conservation measure. A resource cost-benefit analysis of the feasibility of abandoning bulk metering in apartments shows that such a move would yield significant resource benefits, amounting to over 26 billion kilowatt-hours by the turn of the century.

As shown in Exhibit VII-1, a move to individual metering would mean an increase of approximately $136 million in operating and maintenance costs for the next 25 years. However, caution estimates of resource savings fall in the area of $166 million for the same period, so that an aggregate resource benefit of at least $30 million could be realized with such a move.

Appendix V of this volume provides the full resource cost-benefit analysis, studying the feasibility of abandoning bulk metering.

B. RESIDENTIAL TIME-OF-DAY METERING

Two-rate metering of residential load would enhance the application of marginal cost-based rates. The rates would track cost and provide an incentive for reduced peak-load consumption. This in turn could result in lower capital requirements. Appendix VI of this volume is an economic comparison of single-rate and two-rate metering in Ontario to 1995. However, considerable caution must be used in interpreting the results for the following reasons:

1. The estimated benefits of time-of-day metering depend on the assumed elasticity and cross-elasticity of demand figures employed in the study. It should be made clear that these figures were assumed. Up until now, there have been no demand-elasticity studies undertaken in Ontario elsewhere measuring the peak-period demand elasticity, and the cross-price elasticity of demand.

2. The results of other studies such as the five-year British experiment do not give clear-cut results.

3. The costs of conversion to two-rate metering are significant and well-known. They are enumerated in some detail in Appendix VI.

Given the results of the study and the above cautions, the following course of action is proposed:

1. *A study should be conducted to test two-rate metering in actual use on a sufficiently large scale to determine residential customer response to marginal-cost based peak off-peak rates.*

2. *Consideration should be given to offering optional time-of-use rates, that is two-rate metering for customers who have off-peak oriented loads and may feel that they are presently subsidizing peak users.*

3. *Consideration should be given to implementing two-rate metering on a broad basis, if the study suggested above indicates that customer response is sufficient to ensure a net benefit to society.*

It should be noted that both the bulk metering study and the residential time-of-use meter study are resource cost-benefit studies. For example, in the bulk metering study, present value estimates of the resource savings and resource costs of the policy options were developed in order to establish whether there is a net resource cost or savings associated with the abandonment of bulk metering. The results of such a study provide valuable information to the decision-making process. However, it is important to consider the other factors which were not measured in the study in making a final decision.

The following is illustrative of the items which would be used in full but technically more difficult economic cost-benefit study. Consider the bulk metering issue.

Exhibit VII-1

OVERVIEW OF RESOURCE COST-BENEFIT ANALYSIS

COST STREAM

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1. Costs of Abandoning Bulk Metering

a. Resource Costs

The resource costs associated with abandoning bulk metering relate to the additional costs of individual metering, that is, conversion (labour, installation, and associated material), meter reading, customer billing and collection, and regular testing and recalibration.

b. Loss in Consumers' Surplus

Residents of a bulk-metered apartment face a zero marginal price. As a result, they consume more electricity than they otherwise would if they were individually metered. This additional consumption does have some value to the consumer which is lost in moving to individual metering. This lost value is referred to as a loss in consumers' surplus.

2. Benefits of Abandoning Bulk Metering

a. Resource Savings

Resource savings which result from lower consumption levels under individual metering consist of three parts: energy savings, capacity savings, and reduced environmental costs associated with the production of electricity. Energy savings consist of the fuel and variable operation and maintenance expenses incurred by the generating unit. Capacity savings consist of the capital costs and variable expenses associated with building and maintaining a system with sufficient capacity. While it was possible to estimate both energy and capacity savings, only a partial estimate could be made of the environmental savings.

b. Psychic Benefits

There are psychic benefits associated with individual metering in the sense that the customer ''pays for what he gets'' and does not have to be concerned about subsidizing another's consumption.

c. Reduction in External Costs

Lower consumption levels mean less electricity is produced. A reduction in production leads to a reduction in the environmental costs associated with the production of electricity.

d. Conservation Benefits

There may be an additional value to be placed on the resource savings representing the value of redistributing current consumption to future consumption. (See Volume VI, Section III.)

Because of the time available and the severe lack of data, reasonable estimates could only be developed for resource costs and resource savings. The same constraints existed in the time-of-use metering study.

3. The Minimum-Bill Practice

While it is recognized that the existing minimum-bill practice is being phased out in the rural retail system, it is proposed that the practice should be phased out in all retailing utilities, and that a monthly customer charge should be adopted in its place which does not include any kilowatt-hour consumption. Removal of the minimum bill would be more consistent with rates that track costs.

It is to be noted that this proposal does not refer to s
mum charges, required as protection of constructio
case of customer default, as there is no sound reaso
commending the discontinuance of such a practice

4. Flat-Rate Water Heaters

It is proposed that flat-rate billing for electric water h
should be phased out, since such rates do not track
such instances, the marginal price to the end user is
the customer is not aware of the costs associated w
ing a little more or a little less electrical energy.

5. Special Rates

It is proposed that special rates, such as those for el
ing, cooking, water heating, and special discounts,
rate impact discounts, should be phased out, in ord

1. all rates may track costs; and

2. the consensus criterion of fairness, which states
   price structure should impersonal (that is, no pr
   nation) may be met.

APPENDIX I: PROJECTED RATES FOR 1977, 1978 AND 1979 UNDER
               EXISTING RATE STRUCTURE AND PRICING METHODOLOGY

ASSUMPTIONS - DIRECT CUSTOMERS

1.   That the total revenue to be recovered by this class in
     the years 1977, 1978 and 1979, together with the annual
     percentage increase and the annual municipal common costs,
     as well as the effect of conservation on total loads and
     energies are all as published in Financial Forecast # 760529.

2.   That the energy rate for 1977 was set at 9.25 mills per
     kWh by increasing the 1976 rate of 7.0 mills by approxi-
     mately 33.7% the class increase for 1977.

3.   That the energy rates for the years 1978 and 1979 were set
     at 1.025¢ and 1.125¢ respectively by increasing the 1977
     energy rate by approximately the same percentage applicable
     to the class as a whole.

4.   That the increase to the furnace customers for 1977 was
     arbitrarily set at approximately 8% above that of the
     main class, that is approximately 42%, while in the years
     1978 and 1979 increases of 24% and 18% respectively were
     indicated if these loads are to be billed at regular rates
     in 1980.

5.   That existing interruptible classes of power and their
     discounts will continue throughout the period of the study.

6.   That standby revenue will not change appreciably.

1977 RATE MODIFICATION STUDY

Direct Customers
Rate Adjustment Summary

TOTAL REVENUE REQUIRED			$265,234,000

Less: Gananoque E.L. & W.S.	$ 776,309	
Ontario-Minnesota (Export)	4,201,633	
Great Lakes Corporation	13,088,073	
Electric Furnaces	12,101,180	
Standby Service	336,106	30,503,301

Revenue required from Main Class	234,730,699

Less: Revenue from Energy Billing - 14,534,222,000 kWh @ 0.925¢	134,441,554

* Revenue Required from Demand Billing - Main Class $100,289,145

* DERIVATION OF REVENUE FROM DEMAND BILLING - Main Class

Class of Power	Total Billing kW	Proposed Rate $/kW/month	
230 kV - Firm	4,580,509	4.04	$ 18,505,256
- Int. "A"	164,565	3.25	534,836
115 kV - Firm	9,917,908	4.17	41,357,676
- Int. "A"	1,670,128	3.38	5,645,033
- Int. "B"	280,345	2.98	835,428
- Scheduled "C"	129,466	2.74	354,737
12-60 kV - Firm	5,301,847	4.38	23,222,090
- Int. "A"	977,105	3.59	3,507,807
- Int. "B"	1,463,311	3.19	4,667,962
Under 12 kV - Firm	324,269	4.59	1,478,667

Estimated revenue from demand billing - Main Class	$100,109,492

ESTIMATED EFFECT OF RATE ADJUSTMENT

REVENUE:

At Indicated Rates	$265,054,000
At Existing Rates	198,188,000
Difference	$ 66,866,000
% Increase to class	33.7

1978 RATE MODIFICATION STUDY

Direct Customers
Rate Adjustment Summary

TOTAL REVENUE REQUIRED $339,483,000

Less: Gananoque E.L. & W.S. $ 1,113,840
       Ontario-Minnesota (Export)   4,626,346
       Great Lakes Corporation   16,400,965
       Electric Furnaces   18,127,722
       Standby Service   336,106   40,604,979

Revenue required from Main Class   298,878,021

Less: Revenue from Energy Billing
              16,807,760,000 kWh @ 1.025¢   172,279,540

* Revenue required from Demand Billing - Main Class
                                  (a target)   126,598,481

* DERIVATION OF REVENUE FROM DEMAND BILLING - Main Class

Class of Power	Total Billing kW	Proposed Rate $/kW/month	
230 kV - Firm	5,312,487	4.53	$ 24,065,566
- Int. "A"	107,080	3.74	400,479
115 kV - Firm	11,207,274	4.66	52,225,897
- Int. "A"	1,721,414	3.87	6,661,872
- Int. "B"	296,420	3.47	1,028,577
- Scheduled "C"	125,914	3.23	406,702
12-60 kV - Firm	6,036,132	4.87	29,395,963
- Int. "A"	1,148,751	4.08	4,686,904
- Int. "B"	1,638,808	3.68	6,030,813
Under 12 kV - Firm	333,137	5.05	1,682,342

Estimated revenue from demand billing - Main class $126,585,115

ESTIMATED EFFECT OF RATE ADJUSTMENT

REVENUE:

At Indicated Rates   339,470,000
At Existing Rates   304,196,000

    Difference   35,274,000

    % Increase to class   11.6

1979 RATE MODIFICATION STUDY

Direct Customers
Rate Adjustment Summary

TOTAL REVENUE REQUIRED		$412,263,000
Less: Gananoque E.L. & W.S.	$ 1,445,660	
Ontario-Minnesota (Export)	5,066,699	
Great Lakes Corporation	21,014,284	
Electric Furnaces	25,367,241	
Standby Service	336,106	53,229,990
Revenue required from Main Class		359,033,010
Less: Revenue from Energy Billing		
18,240,294,000 kWh @ 1.125¢		205,203,308
* Revenue required from Demand Billing - Main Class		151,829,702
(a target)		

* DERIVATION OF REVENUE FROM DEMAND BILLING - Main Class

Class of Power	Total Billing kW	Proposed Rate $/kW/month	
230 kV - Firm	5,731,962	5.04	$ 28,889,088
- Int. "A"	129,703	4.25	551,238
115 kV - Firm	12,545,684	5.17	64,861,186
- Int. "A"	1,807,567	4.38	7,917,143
- Int. "B"	336,049	3.98	1,337,475
- Scheduled "C"	127,970	3.74	478,608
12-60 kV - Firm	6,414,059	5.38	34,507,637
- Int. "A"	1,230,412	4.59	5,647,591
- Int. "B"	1,873,622	4.19	7,850,476
Under 12 kV - Firm	330,154	5.38	1,776,229
Estimated revenue from demand billing - Main Class			$153,816,671

ESTIMATED EFFECT OF RATE ADJUSTMENT

REVENUE:

At Indicated Rates	412,250,000
At Existing Rates	373,089,000
Difference	39,161,000
% Increase to class	10.5

Residential - Year Round
(Quarterly Rates)

	1R1-11	PR1-11 ER1-11	1R2-11	PR2-11 ER2-11
Basic Quarterly Charge	$2.25	$2.25	$2.25	$2.25
First 750 kWh-¢ per kWh	5.9	5.9	6.45	6.45
Next 1,500	-	2.25	-	2.25
Next 1,500	2.43	2.43	2.45	2.45
Balance	2.35	2.35	2.35	2.35
Minimum Monthly Charge	4.00	4.00	4.00	4.00

Residential - Intermittent Occupancy
(Annual Rates)

	1R3-11	1R4-11
Basic Annual Charge	$63.00	$63.00
First 1,800 kWh-¢ per kWh	5.25	5.4
Next 1,200	2.9	3.05
Next 6,000	2.33	2.55
Balance	2.35	2.35

Farm Service (Monthly Rates)
Kilowatt Charge

	1F2-11 1F2-13	PF2-11 PF2-13	1F2-31 & PF2-31 1F2-33 PF2-33
Basic Charge	0.75	0.75	0.75

Kilowatt Charge

	1F2-11 1F2-13	PF2-11 PF2-13	1F2-31 & PF2-31 1F2-33 PF2-33
First 50 kW or less	-	-	-
Balance per kW	$2.00	$2.00	$3.20

Energy Charge

	1F2-11 1F2-13	PF2-11 PF2-13	1F2-31 & PF2-31 1F2-33 PF2-33
First 250 kWh-¢ per kWh	6.6	6.6	8.4
Next 500	-	2.25	-
Next 500	2.6	2.6	-
Next 8,750	-	2.45	-
Next 9,250	2.45	-	-
Next 9,750	-	-	2.85
Next 490,000	-	-	1.35
Next 1,500,000	-	-	1.21
Balance	1.6	1.6	0.9
Minimum Monthly Charge	$4.00*	$4.00*	$5.00*

General Service (Monthly Rates

	1G2-11 & PG2-11 & 1G2-31 & PG2-31
	1G2-13 PG2-13 1G2-33 PG2-33
Basic Charge	0.75

Kilowatt Charge

First 50 kW or less	
Balance per kW	$3.20

Energy Charge

First 250 kWh-¢ per kWh	8.4
Next 9,750	2.85
Next 490,000	1.35
Next 1,500,000	1.21
Balance	0.9
Minimum Monthly Charge	$5.00*

*Plus 25¢ per kW of maximum demand in excess of 50 kW
 established in previous eleven months.

A late-payment charge of 5 per cent is assessed on the
 unpaid balance of current charges for metered energy,
 minimum bills, demand charges and fixed charge accounts.

Residential - Year Round
(Quarterly Rates)

	1R1-11	PR1-11 ER1-11	1R2-11	PR2-11 ER2-11
Basic Quarterly Charge	$4.50	$4.50	$5.25	$5.25
First 750 kWh - ¢ per kWh	6.5	6.5	7.0	7.0
Next 1,500	-	2.6	-	2.6
Next 1,500	2.7	2.7	2.7	2.7
Balance	2.65	2.65	2.65	2.65

Residential - Intermittent Occupancy
(Annual Rates)

	1R3-11	1R4-11
Basic Annual Charge	$67.20	$68.40
First 2,400 kWh - ¢ per kWh	5.8	5.9
Next 600	3.4	3.5
Next 6,000	2.5	2.7
Balance	2.65	2.65

Farm Service (Monthly Rates)

	1F2-11 1F2-13	PF2-11 PF2-13	1F2-31 1F2-33 & PF2-31 PF2-33
Basic Charge	$1.75	$1.75	$1.75
Kilowatt Charge			
First 50 kW or less	-	-	-
Balance per kW	$2.00	$2.00	$3.20
Energy Charge			
First 250 kWh - ¢ per kWh	7.1	7.1	8.8
Next 500	-	2.6	-
Next 500	2.8	2.8	-
Next 8,750	-	2.7	-
Next 9,250	2.7	-	-
Next 9,750	-	-	3.1
Next 1,990,000	-	-	1.5
Balance	2.1	2.1	1.025
Minimum Monthly Charge	$4.00*	$4.00*	$5.00*

General Service (Monthly Rates)

	1G2-11 1G2-13 &	PG2-11 PG2-13 &	1G2-31 1G2-33 &	PG2-31 PG2-33
Basic Charge		$1.75		
Kilowatt Charge				
First 50 kW or less		-		
Balance per kW		3.20		
Energy Charge				
First 250 kWh - ¢ per kWh		8.8		
Next 9,750		3.1		
Next 1,990,000		1.5		
Balance		1.025		
Minimum Monthly Charge		$5.00*		

* Plus 25¢ per kW of maximum demand in excess of 50 kW established in previous eleven months.

A late-payment charge of 5 per cent is assessed on the unpaid balance of current charges for metered energy, minimum bills, demand charges and fixed charge accounts.

Residential - Year Round
(Quarterly Rates)

	1R1-11 PR1-11 ER1-11	1R2-11 PR2-11 ER2-11
Basic Quarterly Charge	$6.75	$9.00
First 750 kWh - ¢ per kWh	7.2	7.5
Balance	2.95	2.95
Minimum Monthly Charge	$4.00	$4.00

Residential - Intermittent Occupancy
(Annual Rates)

	1R3-11	1R4-11
Basic Annual Charge	$69.60	$73.20
First 3,000 kWh - ¢ per kWh	6.5	6.55
Next 6,000	2.6	2.8
Balance	$2.95	$2.95

Farm Service (Monthly Rates)

	1F2-11 & PF2-11 1F2-13 & PF2-13	1F2-31 & PF2-31 1F2-33 & PF2-33
Basic Charge	$3.00	$3.00
Kilowatt Charge		
First 50 kW or less	-	-
Balance - per kW	1.00	3.30
Energy Charge		
First 250 kWh - ¢ per kWh	7.6	9.2
Next 9,750	2.95	3.35
Next 1,990,000	-	1.7
Balance	2.65	1.125
Minimum Monthly Charge	$4.00*	$5.00*

General Service (Monthly Rates)

	1G2-11 & PG2-11 1G2-13 & PG2-13	1G2-31 & PG2-31 1G2-33 & PG2-33
Basic Charge		$3.00
Kilowatt Charge		
First 50 kW or less		-
Balance per kW		3.30
Energy Charge		
First 250 kWh - ¢ per kWh		9.2
Next 9,750		3.35
Next 1,990,000		1.7
Balance		1.125
Minimum Monthly Charge		$5.00*

* Plus 25¢ per kW of maximum demand in excess of 50 kW established in previous
11 months.

A late-payment charge of 5% is assessed on the unpaid balance of current charges
for metered energy, minimum bills, demand charges and fixed charge accounts.

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	1.05	.93	.84	.80
Working Capital (%)	0.4	6.4	7.4	8.1
Rate of Return (%)	7.0	6.2	5.7	5.4

Rates

Residential

	1975	1977	1978	1979
Minimum		3.50	3.50	4.00
First 50 kWh		5.9	6.0	6.8
Next 200 kWh		3.1	3.2	3.7
Next 500 kWh *		2.15	-	-
Balance		2.25	2.5	2.75
FRWH		129	150	165

* Water Heater Block

General

	1975	1977	1978	1979
Demand Charge				
First 50 kW		-	-	-
Balance kW		2.20	2.20	2.20
Energy Charge				
Minimum		3.50	3.50	4.00
First 50 kWh		5.9	6.0	6.8
Next 200 kWh		3.4	3.5	4.0
Next 9750 kWh		2.75	3.0	3.25
Balance		1.65	1.9	2.15

Miscellaneous

	1975	1977	1978	1979
FRWH		129	150	165
Sentinal Lights		8.95	9.94	10.93
Street Lights		8.14	9.04	9.94

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	0.68	0.68	.60	.70
Working Capital (%)	2.6	2.4	2.8	3.1
Rate of Return (%)	5.7	5.9	5.4	6.0

Rates

Residential

	1975	1977	1978	1979
Minimum		4.00	4.00	4.00
First 50 kWh		5.4	5.5	6.3
Next 200 kWh		2.7	2.8	3.3
Next 500 kWh *		2.15	-	-
Next 500 kWh **		1.95	2.3	2.55
Balance		2.25	2.5	2.75
FRWH		117	135	149

* Water Heater Block
** Controlled Water Heater Block

General

	1975	1977	1978	1979
Demand				
First 50 kW		-	-	-
Balance		2.50	2.50	2.50
Energy				
Minimum		4.00	4.00	4.00
First 50 kWh		5.4	5.5	6.3
Next 200 kWh		3.0	3.1	3.6
Next 9750 kWh		2.75	3.0	3.25
Balance		1.5	1.75	2.00

Miscellaneous

	1975	1977	1978	1979
Sentinal Light		8.69	9.68	10.67
Street Light		7.90	8.80	9.70

Elora - Proposed Rates

AIB Criteria	1975	1977	1978	1979
Profit/MWh ($) 95% of 5 yr Ave = .49	.04	.43	.41	.43
Working Capital (%)	6.1	5.8	6.2	6.4
Rate of Return (%)	0.3	3.9	5.2	6.1

Rates

Residential

	1975	1977	1978	1979
Minimum		3.50	3.50	3.50
First 250 kWh		4.6	4.9	5.6
Next 500 kWh *		2.15		
Balance		2.25	2.5	2.75
FRWH		129	150	165

* Water Heater Block

General

	1975	1977	1978	1979
Demand				
First 50		-	-	-
Balance		2.20	2.20	2.20
Energy				
Minimum		3.50	3.50	3.50
First 250 kWh		4.7	5.0	5.7
Next 9750		2.70	3.0	3.25
Balance		1.60	1.9	2.15

Miscellaneous

	1975	1977	1978	1979
FRWH				
Sentinal Light		8.76	9.94	10.93
Street Light		7.96	9.04	9.94

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	.81	.81	.79	.81
Working Capital (%)	9.7	10.8	11.4	12.6
Rate of Return (%)	4.0	4.2	4.0	4.2

Rates

Residential

		1977	1978	1979
Minimum		3.50	3.50	3.50
First 50 kWh		5.0	5.25	5.85
Next 200 kWh		2.6	2.85	3.45
Next 500 kWh *		2.15	-	-
Balance		2.25	2.50	2.75

* Water Heater Block

General

Demand	1977	1978	1979
First 50 kW	-	-	-
Balance	2.30	2.30	2.30

Energy			
Minimum	3.50	3.50	3.50
First 50 kWh	5.0	5.25	5.85
Next 200 kWh	2.8	3.05	3.65
Next 9750 kWh	2.75	3.0	3.25
Balance	1.60	1.85	2.10

Miscellaneous

	1977	1978	1979
Street Light	8.06	8.96	9.86

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	1.79	1.79	1.77	1.83
Working Capital (%)	5.6	2.9	2.5	2.6
Rate of Return (%)	11.3	10.3	9.8	9.8

Rates

Residential

		1977	1978	1979
Minimum		4.00	4.00	4.00
First 50 kWh		7.6	8.35	9.15
Next 200 kWh		3.9	4.4	4.8
Balance		2.25	2.5	2.75
FRWH		90	100	110

General

		1977	1978	1979
Demand Charge				
First 50 kW		-	-	-
Balance		2.60	2.60	2.60
Energy Charge				
Minimum		4.00	4.00	4.00
First 50 kWh		7.6	8.35	9.15
Next 200 kWh		3.9	4.4	4.8
Next 9750 kWh		2.75	3.0	3.25
Next	2,200,000	1.55 / 2,580,000	1.7 / 3,170,000	1.95
Balance		.925	1.025	1.125
Large User Demand		5.37	6.10	7.85
Energy		0.925	1.025	1.125

Miscellaneous

	1977	1978	1979
Sentinal Lighting	8.60	9.59	10.58
Street Lighting	7.82	8.72	9.62

Oakville - Proposed Rates

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	1.92	1.38	1.59	1.74
Working Capital (%)	11.8	9.5	11.9	11.4
Rate of Return (%)	14.7	9.7	9.7	10.4

Rates

Residential

	1977	1978	1979
Minimum	4.00	4.00	4.00
First 50 kWh	8.6	9.6	11.2
Next 200 kWh	4.4	4.9	5.7
Next 500 kWh *	2.15	2.4	-
Next 500 kWh **	1.95	2.25	2.55
Balance	2.25	2.5	2.75
FRWH	112	125	136

* Water Heater Block
** Controlled Water Heater Block

General

Demand

	1977	1978	1979
First 50 kW	-	-	-
Balance	2.90	2.90	2.90

Energy

	1977		1978		1979	
Minimum		4.00		4.00		4.00
First 50 kWh		8.6		9.6		11.2
Next 200 kWh		4.8		5.2		6.0
Next 9750 kWh		2.80		3.05		3.3
Next	2,130,000	1.50	2,290,000	1.7	2,440,000	1.9
Balance		0.925		1.025		1.125

Large User

	1977	1978	1979
Demand	5.36	6.00	6.70
Energy	0.925	1.025	1.125

Miscellaneous

	1977	1978	1979
Sentinal Light	9.13	9.92	10.71
Street Light	8.30	9.02	9.74
Commercial Cooking	2.8	3.05	3.3
Commercial Heating	2.8	3.05	3.3

Ottawa Rates

AIB Criteria	1975	1977	1978	1979
Net Profit/MWh ($)	1.78	1.52	1.79	1.64
Working Capital (%)	9.5	12.1	13.5	14.2
Rate of Return (%)	10.1	8.5	10.1	8.6

Rates

Residential

		1977	1978	1979
Minimum		3.50	3.50	4.00
First 50 kWh		5.4	6.1	7.0
Next 200 kWh		2.7	3.4	4.0
Balance		2.25	2.5	2.75

General

		1977	1978	1979
Demand				
First 50 kW		-	-	-
Balance		2.80	2.80	2.80
Energy				
Minimum		3.50	3.50	4.00
First 50 kWh		6.0	6.1	7.0
Next 200 kWh		3.6	3.7	4.3
Next 9750 kWh		2.75	3.0	3.25
Next	1,935,000	1.55	2,160,000 1.75	2,540,000 1.9
Balance		0.925	1.025	1.125
Large User				
Demand		5.23	5.95	6.75
Energy		0.925	1.025	1.125

Miscellaneous

		1977	1978	1979
Street Lighting		8.38	9.28	10.00

AIB Criteria	1975	1977	1978	1979
Net Profit /MWh ($)	1.09	1.09	1.07	1.10
Working Capital (%)	(4.3)	0.6	0.9	1.6
Rate of Return (%)	14.4	15.2	14.7	14.6

Rates

Residential

	1975	1977	1978	1979
Minimum		3.50	4.00	4.00
First 50 kWh		8.0	8.0	8.5
Next 200 kWh		4.0	4.0	4.3
Balance		2.25	2.5	2.75
FRWH		112	128	140

General

Demand

	1975	1977	1978	1979
First 50 kW		-	-	-
Balance		2.70	2.70	2.70

Energy

	1975	1977	1978	1979
Minimum		3.50	4.00	4.00
First 50		8.0	8.0	8.5
Next 200		4.0	4.0	4.3
Next 9750 kWh		2.75	3.0	3.25
Next	2,380,000	1.50 2,580,000	1.7 2,590,000	1.95
Balance		.925	1.025	1.125

	1975	1977	1978	1979
Large User Demand		5.45	6.20	7.00
Energy		.925	1.025	1.125

Miscellaneous

	1975	1977	1978	1979
FRWH		112	128	140
Sentinal Lights		8.91	9.70	10.69
Street Lights		8.10	8.82	9.72

APPENDIX II: Rationale for Folding the Demand Charge into the Energy Charge for 0-50 kW Users

During the development of the common general rate structure for commercial and industrial customers in the mid-1960's, the following observations were made:

1. The demand charge for small customers is responsible for a great deal of confusion and customer annoyance. With a demand-sensitive rate the small customer can receive a dramatic increase in his bill, upon adding a new appliance such as a water heater or air-conditioner.

2. Today we have a large integrated system, the diversity among low load factor loads is relatively high, and consequently, the individual use pattern of the relatively small customers is not nearly so important as it was years ago; individual demands of small customers are insignificant.

3. The small customer cannot exercise sufficient control over his pattern of use of electricity to improve load factor as his requirements are dictated by the events in his business.

4. The large user, on the other hand, is in a better position to engage in load-moulding, particularly in the case of a manufacturing or processing industry where a multitude of electrical machines and devices are employed. Demand rates seem justified for large users.

5. 96 per cent of commercial customers have demands less than 50 kilowatts. It goes without saying that extension of energy rates to this level would simplify the metering, billing, and administrative requirements for commercial customers tremendously. Demand meters would be required for less than 10 percent of commercial and industrial customers.

6. A dividing-point of 50 kilowatts to commence application of a demand charge offers several advantages:

   a. It is high enough to be effective in eliminating excessive impact on customer's bills due to the additional demand of a new appliance.

   b. It corresponds to a 200-ampere service rating.

   c. It is well below the level of significance in respect to the supply system demand.

7. Load analysis of actual utility statistics provided the following observations.

	Customers in Hours of Use Intervals		
	0-100	101-300	Over 300
0-50 kW	28%	54%	18%
50-500 kW	5%	59%	26%
over 500 kW	2%	33%	65%

While fairly wide variations in hours of use existed for individual customers, the mean for the entire group from 0 to 50 kilowatts was approximately 200 hours' use per month.

The rate system that evolved was a simple block-energy rate structure for small users, consisting of short initial blocks to cover the fixed or customer portions of the cost of service and an end rate. The system introduced a demand charge at 50 kilowatts. The demand charge applies to the load in excess of 50 kilowatts, and a further reduction in the block-energy rates takes place at the consumption point corresponding to the average hours' use of customers at this load level (i.e., 10,000 kilowatt-hours per month - 50 kilowatts, 200 hours' use). This type of structure avoids a sharp inflection in the customer's bill at the 50 kilowatt point, accomplishes a gradual transition from a pure energy rate to a demand-responsive rate, and recognizes the in-

crease in co-incidence with load factor. By proper pricing of the structure, an increase in unit costs to larger users of average load factor or better, can be avoided. For example, if a customer doubles his load from 50 to 100 kilowatts, the average rate for the second 50 kilowatts should not be greater than that for the first 50 kilowatts.

As there is no logically sound reason for recommending a return to demand-sensitive rates for general class customers with loads below 50 kilowatts, with the resultant increase in metering, meter reading, billing and administrative expenses, the present 50 kilowatt load level at which the demand charge would take effect, has been retained, along with the corresponding 10,000 kilowatt-hours initial energy block, representing 200 hours' use of 50 kilowatts.

While there may be wide variations between use and rate of use for individual customers within the group below 50 kilowatts, on average, load factor can be assumed to be constant over rate of use up to 50 kilowatts.

To set rates for the initial 10,000 kilowatt-hour block, it is as necessary to fold the demand charge into the energy charge for the 0-50 kilowatt general class customers, as it is for the residential classes.

Load Factor is defined as follows: $LF = kWh/kW.t = .274$, for example, where

1. LF = load factor;

2. t = some time interval (say 730 hours);

3. kWh = kilowatt-hours consumed in time interval t; and

4. kW = maximum demand in time interval t.

Hence, if $KwH/kW = c$ (a constant), then $LF = c.(1/t) = 2.74$ (a constant).

Now, assume for illustrative purposes that

1. kW charge = $2.00;

2. kWh charge = 1¢/kWh;

3. usage = 730,000 kWh; and

4. LF = .274

In order to determine the appropriate charge per kilowatt-hour, the revenue requirement of the 0-50 kilowatt user class must be determined.

1. $kW = kWh/LF.t = 730,000(.274)(730) = 3650kW$;

2. kW charge applicable to energy = 3650 x $2 = $7300;

3. kWh charge = 730,000x1¢ = 7300;

4. Revenue requirement = $7,300 + $7,300 = $14,600; and

5. The rate per kWh = revenue requirement/kWh = $14,600/730,000 kWh = 2.0¢/kWh.

APPENDIX III: Large Electricity-User Rates and Bills

Section A of this appendix provides a description of the methodology employed in the derivation of electricity rates and bills for large-use customers.

Section B describes and analyses the results of a computer simulation model which calculates large user bills, under the proposed and alternative pricing-systems.

A. METHODOLOGY FOR, AND CALCULATION OF, LARGE-USER RATES

Under the recommended pricing-system, there would be seasonal time-of-day rates for large industrial users with monthly power demands of 5,000 kilowatts and greater. The large user would face a four-part charge consisting of

1. Demand Charge

The demand charge would be based on the marginal costs associated with the rate of use of kilowatt-hours, that is, kilowatts. Each customer's demand charge would be based on the customer's monthly non-coincident peak demand during the daily peak period of 7:00 to 23:00, Monday through Friday, exclusive of statutory holidays. The demand charge would be seasonally adjusted (summer and winter) to reflect cost differences based on loss of load probabilities across the yearly peak and off-peak periods.

2. Peak-Energy Charge

This charge would also be differentiated on a summer-winter basis, and would reflect the marginal costs associated with providing energy in the daily peak period.

3. Off-Peak Energy Charge

The off-peak energy charge would be based on the marginal costs associated with providing off-peak energy, from 23:00 to 7:00, on Monday through Friday, plus all day on weekends and statutory holidays.

4. Customer Charge

The customer charge would be based on the avoidable costs associated with serving each customer, plus the costs which do not vary with kilowatt-hours or kilowatts.

This appendix will not deal with individual customer charges as they are independent of the use, or rate of use, of energy. Thus, any hypothetical customer bills which are developed in this appendix will not include customer charges.

If all large users had all of their demand and energy priced at marginal costs, the revenue accruing to Ontario Hydro would exceed the large-user-class revenue requirement which is based on historical accounting costs. Thus, the task of the rate structure methodology is to price electricity so as to not fall short of or exceed the revenue requirement, while at the same time ensuring that the electricity user is aware of the cost consequences of his consumption decision.

The pricing methodology to achieve this objective may be briefly described. It is one wherein any growth or decline in the customer's demand or energy over a specified time period is priced to reflect its marginal cost or saving to the electricity supplier. The customer's baseline demand and energy is priced at a unit costing average rate. The result is that changes in kilowatt and kilowatt-hour consumption are priced at marginal cost, and yet, no revenue surplus accrues to the utility. Prior to the analysis which will describe the derivation of the unit costing average rate, some definitions are required.

1. Definitional Considerations

a. Large User

Any customer, of either Ontario Hydro or a municipal utility, with a monthly non-coincident demand greater than 5,000 kilowatts. Large users, whether supplied by a municipality or by Ontario Hydro as direct customers, should be in the same class in order that the same kilowatt and kilowatt-hour rates should apply to all customers.

b. Summer Season

April 1 through September 30;

c. Winter Season

January 1 to March 31, plus October 1 to December 31 of any given calendar year;

d. Peak Period

07:00 to 23:00 (16 hours), Monday to Friday, exclusive of statutory holidays;

e. Off-Peak Period

23:00 - 07:00 (8 hours) every day, and 24 hours a day on weekends and statutory holidays;

f. Energy Usage

In the calculation of energy-unit costing-rates, firm, interruptible A and B bulk interruptible, and scheduled C power are all included to arrive at total large-user kilowatt-hours.

g. Choice of Time Period to Reflect Growth kW and kWh.

A three year spread between baseline usage and the bill year may be an optimum trade-off in affecting marginal energy consumption and demand adjustments by large users. The rationale behind the choice of a three-year period is predicated on the assumption that large industry when examining possible changes in complements or processes of all but major plant locational decisions, may not undertake an investment if the payback period is greater than three years. In other words, if some change in the company's staff, machinery or operations has not paid for itself in three years, it is generally a questionable economic decision.

The company will therefore consider an incremental increase in energy or demand which is priced at marginal cost, only if the increased cost has been recovered in under three years. Choice of a lower time lag such as one or two years may cause industry to respond to the baseline rate in the future. For example, if the 'lag were one year, a large user might not hesitate in increasing load and energy substantially in 1977, and absorbing the high marginal costs for one year, during which his 1977 usage would be priced at the lower baseline rate. On the other hand, a lag of greater than three years would start to create administrative problems. Cost trade-offs may not justify the marginal increase in the integrity of the electricity cost information that would occur under a longer rolling-time period. Also, one might argue that long rolling-time periods may affect the distributional neutrality of the large user pricing rule.

Clearly, the selection of an appropriate time period must insure the integrity of the price signal in a large user's decision-making process. A price signal reflecting marginal costs to the utility will make the marginal customer decisions to conserve economical.

2. Derivation of Unit Costing Average Rates: Demand

The analysis will result in 1977 unit costing average rates to be applied to baseline usage (which for 1977 rates is that of 1974). The methodology is constant from year to year and as a result the mechanics of the development of the 1978 and 1979 rates will not be illustrated.

Preparatory Information and Calculation, 1974 Demand by Large Users

1. Ontario Hydro Large Users: 2,069 MW

2. Municipality Large Users: 1,262 MW

3. Adjustment: -46 MW

4. Total Large-User Demand: 3,285 MW

The adjustment takes into account the large use customer load on line in 1974, but not in 1977. These kilowatts must be subtracted from the total 1974 kilowatts so that total 1974 kilowatt usage, priced at 1977 unit costing average rates, plus the 1974-77 kilowatts, priced at marginal cost based rates, equal the 1977 revenue requirement. Somewhat off-setting those customers are the ones who in the time period from 1974 to 1977, have made a special class-change from rural or retail to large-user. These customers must have their average 1974 load added to the large-user class kilowatt load for the same reasons as above. The net result of the subtraction (64MW)[4] and addition (18MW)[5] is a net negative adjustment factor of 46 MW. This adjustment has only been done for the 1977 rates, because forecasts are not sufficiently accurate to anticipate customer movement between 1975 and 1978, and 1976 and 1979.

The 1974 large user demand must now be split into summer and winter components. Using a summer-winter split of .988 to 1.-012 (as in the NERA marginal cost study) of total average large-user load we have

1. 1974:

   a. Summer 3285 X .988 = 3246 MW

   b. Winter 3285 X 1.012 = 3324 MW

The 1977 large-user class demand for Ontario Hydro and the municipalities is projected to be 3841 MW. Using the same summer-winter apportioning factors this gives

2. 1977:

   a. Summer 3841 X .988 = 3795

   b. Winter 3841 X 1.012 = 3887

Growth in large user demand from the baseline period, 1974 to 1977 is easily found to be

3. 1974-77:

   a. Summer: 549 MW

   b. Winter: 563 MW

   c. Average 1974-77: 556 MW

3. DERIVATION PROCESS FOR UNIT COSTING AVERAGE

Step 1

If there were no load growth from 1974 to 1977, the 1977 load would cost

1. Summer: 3,246,000 kW x $5.54/kW = $17,982,840

2. Winter: 3,324,000 kW x $33.19/kW = $110,323,560

3. Total: $17,982,840 + $110,323,560 = $128,306,400

$5.54 per kW and $33.19 per kW are the respective average summer and winter demand costs facing the municipalities, and retail and large users. These seasonal pro-rated unit costs are found by using marginal costs, pro-rated to meet revenue requirements. It should be noted that summer and winter demand comprise 14 and 86 per cent of the total cost respectively.

Step 2

However, there has been growth in large-user demand and this will be priced at marginal cost to arrive at revenue attributable to growth.

1. Summer: 549,000 kW x $7.78/kW = $4,271,220

2. Winter: 563,000 kW x $46.63/kW = $26,252,690

3. Total: $4,271,220 + $26,252,690 = $30,523,910

The summer and winter marginal costs of $7.78 per kW and $46.63 per kW are taken from the NERA marginal cost study.[6]

Step 3

Using 1977 large-user loads, along with average costs facing all customer classes, the 1977 demand revenue requirement may be calculated:

1. Summer: 3,795,000 kW x $5.54/kW = $21,024,300

2. Winter: 3,887,000 kW x $33.19/kW = $129,010,000

3. 1977 Revenue Requirement = $21,024,300 + $129,010,000 = $150,034,300

Step 4

To begin the process of ensuring that revenues received do not exceed the revenue requirement, one must subtract total demand growth revenue from Step 2, from the 1977 demand revenue requirement as calculated in Step 3.

1. 1977 Large User Demand Revenue Requirement = $150,034,300

2. 1974-77 Large User Demand Growth Revenue = $30,523,910

3. Difference = $150,034,300 - $30,523,910 = $119,510,390

Before calculating the unit costing-average rate, this remainder can be divided into summer and winter costs on the basis of their proportional share of total 1977 demand costs, if there were no load growth. See Step 1 for derivation of summer (-.14) and winter (-.86) split. Thus, we have

1. Summer: .14 x $119,510,390 = $16,731,454.60

2. Winter: .86 x $119,510,390 = $102,778,935.40

3. Total: $16,731,454.60 + $102,778,933.40 = $119,510,390.00

[4]Bruce Heavy Water Plant.
[5]Hayes Dana and Dupont, St. Clair River Works and Pamour Porcupine (Whitney Twp.)
[6]See Volume 7.

Therefore the 1977 demand revenue requirement, after growth kW priced at marginal cost have been subtracted, has been split on a seasonal basis.

Step 5

Accordingly, if one divides these two costs by the baseline, of 1974 usage, the result will be a unit average costing rate. The potential of producing a surplus is now effectively removed.

1. $16,731,454.60/3,246,000 kW = $5.15/kW

2. $102,778,935.40/3,324,000 kW = $30.92/kW

If the utility prices growth in kW's (1974 to 1977), at marginal costs, and baseline kW (1974) at the above unit costing rate, the total of the two will be the 1977 revenue requirement.

4. Derivation of Unit Costing Average Rates: Energy

The methodology of developing unit costing energy rates for 1977 is identical to that for demand. The presentation of these calculations will therefore be more concise.

Preparatory Information and Calculation: Baseline Energy, 1974

1. Ontario Hydro Large users: 14,862,282,000 kWh

2. Municipal Large users 8,343,999,000 kWh

3. Adjustment: 316,227,328 kWh[7]

4. Total of (1+2)-(3) = 22,890,053,672 kWh

The energy must now be divided into the periods needed to reflect the proposed charges to the large-user. In other words, the amount energy for summer-peak, winter-peak and off-peak periods is required. Following the National Economic Research Associates Study, the split is 24 per cent Summer peak, 26 per cent Winter peak, and 50 per cent Off-peak.

1. Summer Peak: 5,494 Million kWh

2. Winter Peak: 5,951 Million kWh

3. Off-Peak: 11,445 Million kWh

4. Total: 22,890 Million kWh

The 1977 large-user energy use for Ontario Hydro is forecast to be 26,047 million kWh. Using the same apportioning factors we have:

1974

1. Summer Peak: 6,252 Million kWh

2. Winter Peak: 6,772 Million kWh

3. Off-Peak: 13,023 Million kWh

4. Total: 26,047 Million kWh

Therefore growth in energy consumption for large users from 1974 to 1977 is

1. Summer Peak: 758 Million kWh

2. Winter Peak: 821 Million kWh

3. Off-Peak: 1,578 Million kWh

4. Total: 3,157 Million kWh

5. Derivation Process for Unit Costing Average

Step 1

With no growth between 1974 and 1977, 1977 load would cost

1. Summer Peak: 5,494 Million kWh x $0.0124/kWh[8] = $68,125,600 (.257)

2. Winter Peak 5,951 Million kWh x $0.0145/kWh[5] = $86,289,500 (.325)

3. Off-Peak 11,445 Million kWh x $0.0097/kWh[5] = $111,016,500 (.418)

4. Total: $265,431,600 (1.000)

Step 2

Growth is large-user energy would be priced at marginal cost to arrive at revenue attributable to growth:

Marginal energy costs[9]

1. Summer Peak: $.018/kWh

2. Winter Peak: $.021/kWh

3. Off-Peak: $0.14/kWh

Thus

1. Summer Peak = $.018/kWh x 758 million kWh = $13,694,000

2. Winter Peak = $.021/kWh x 821 million kWh = $17,241,000

3. Off-Peak = $.014/kWh x 1,578 million kWh = $22,092,000

4. Total Growth Revenue = $52,927,000

Step 3

Using 1977 large-user energy use and average costs facing all customer classes, the 1977 energy revenue requirement is $301,959,000. If the total large user growth revenue is subtracted from the large users' energy revenue requirement one has: $301,459,000 - 52,977,000 = $248,482,000, which may be split into peak and off-peak revenues in order to determine unit average cost.

Step 4

Using a weighted average corresponding to revenues in Step 1, the remainder from Step 3 may be apportioned as follows:

1. Summer Peak .257 X $248,482,000 = $63,859,874

2. Winter Peak .325 X $248,482,000 = $80,756,650

3. Off-Peak .418 X $248,482,000 = $103,865,476

4. Total = $248,482,000

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[7]As in the demand calculation, the adjustment takes account of those large users who purchased kWh's in 1974 but will not in 1977 and vice-versa. The net negative adjustment of 46,000 kW is converted to kilowatt hours, using a load factor for the Ontario Hydro class of direct customers of 78.5 per cent.
[8]Energy costs facing all classes. (Marginal costs pro-rated to revenue requirement.)
[9]See Volume VII for derivation.

Step 5

To arrive at net unit average costing rates:

1. Summer Peak $63,859,784/5,494,000,000 kWh = $0.01162/kWh

2. Winter Peak $80,756,650/5,951,000,000 kWh = $0.01357/kWh

3. Off-Peak $103,865,476/11,445,000,000 kWh = $0.00907/kWh

6. Proof of Zero Surplus

1. 1977 Large User Demand Revenue Requirement = $150,034,300

2. 1977 Large User Energy Revenue Requirement = $301,459,000

3. 1977 Large User Total Revenue Requirement = $451,493,300

1974-1977 Large User Demand and Energy Growth

Growth x Marginal Cost = Growth Revenue

1. Summer Demand = 549,000 kW x 7.78/kW = 4,271,220

2. Winter Demand = 563,000 kW x 46.63/kW = $26,252,690

3. Summer Peak Energy = 758,000,000 kWh x .018/kWh = $13,644,000

4. Winter Peak Energy = 821,000,000 kWh x .021/kWh = $17,241,000

5. Off-Peak Energy = 1,578,000,000 kWh x .014/kWh = $22,092,000

6. Total Large-User Growth Revenue = $83,500,910

1974 Large-User Demand and Energy

Baseline Use x Unit Costing Rate = Baseline Revenue

1. Summer Demand = 3,246,000 kW x 5.15/kW = $16,731,454.60

2. Winter Demand = 3,324,000 kW x 30.92/kW = $102,778,935.40

3. Summer Peak Energy = 5,494.000,000 kWh x .01162/kWh = $63,859,784

4. Winter Peak Energy = 5,951,000.000 kWh x .01357/kWh = $80,756,650

5. Off-Peak Energy = 11,445,000,000 kWh x .00907/kWh = $103,865,476

6. Total Baseline Revenue = $367,992,300

Thus $367,992,300 + 83,500,910 = $451,493,210, which given rounding error, equals $451,493,300, the 1977 revenue requirement.

Refer to the main body of this volume for three tables illustrating the 1977, 1978, and 1979 large-user rates, under four separate pricing methodologies. (Exhibit IV-3).

B. LARGE USER TOTAL-BILL SIMULATION

A simulation was undertaken in order to assess and analyse customer bills under the proposed pricing system. These bills were then compared with what they would be under three separate pricing approaches, of which the current system is one.

1. Calculation of Large-User Total Bills Under Proposed Pricing-System

To begin with, a computer program (APL) was developed to calculate customer bills under the marginal-cost pricing methodology.

Fifteen large-use customers[10] were randomly chosen, and data on their 1974 and 1977 demand and energy use was obtained. For purposes of this simulation, bills were calculated only for 1977. Future analysis can easily incorporate bill calculations for 1978 and 1979, although the accuracy of demand and energy forecasts decreases the further into the future one estimates. All loads illustrated are assumed to peak during the peak period.

The total-bill calculation was done prior to the release of Ontario Hydro's 1976 Ontario Energy Board rates submission, and as a result, the figures used in this example will not correspond precisely to the official rates.

The available figures from internal information sources are monthly demand and monthly energy. For the data to correspond with the pricing-rule, some assumptions have to be made about the customer's split in kilowatt-hours between peak and off-peak periods. Given discussion with industry combined with examination of system load data and curves, the following cases are developed.

Percentage of Monthly Hours In Perspective Periods

	Summer Energy		Winter Energy	
Case	Peak	Off-Peak	Peak	Off-Peak
1	48.5	51.5	47.5	52.5
2	50.5	49.5	49.5	50.5
3	52.5	47.5	51.5	48.5

While the break between off-peak and peak electricity usage will vary according to each customer, the above sensitivity analysis should provide a workable facsimile of current industrial usage.

In the calculation of 1977 bills, the baseline usage from which growth or decline in demand and energy are priced is 1974. The 1977 figures for the selected customers uses Load Forecast 760209. Given these two matrices, calculation of a growth matrix simply involves subtracting the 1974 table from the 1977 table.

The Baseline (1974), Forecast (1977), and Growth (1974 to 1977) tables will be illustrated for each of the above cases which differentiate the kilowatt-hour amounts in the peak and off-peak periods.

The calculation of a typical summer and winter monthly bill for any given customer would be the summation of the following calculations:

Summer or Winter

1. Baseline Load x Unit Costing Demand Rate,

[10]All 15 are direct customers of Ontario Hydro as their data were most readily available. The data include actual and forecast loads and energy. The customers will not be identified in order to protect their competitive position

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CASE 1

BASELINE (1974) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mthly Winter Off-Peak Period Energy
1	19.6	22.5	5606	5461	388632	426686	412374	471321
2	37.3	47.0	33031	32097	4371993	5233799	4639079	5781289
3	72.1	74.4	11264	10180	2879567	2628066	3055480	2902979
4	50.3	52.3	45630	44435	8141873	8071407	8639262	8915729
5	81.4	83.2	5474	5351	1579759	1545669	1676267	1707357
6	94.5	92.4	96753	97645	32415143	31324871	34395391	34601657
7	57.9	52.5	35127	17523	7213716	3190171	7654403	3523383
8	62.3	68.1	4423	5045	976190	1192632	1035826	1317389
9	41.3	47.5	4396	4164	643839	686119	683171	757892
10	95.4	93.9	25123	24364	8494601	7943591	9013539	8774543
11	71.7	74.4	5589	5112	1420134	1320923	1506890	1459100
12	85.5	85.8	224279	234701	67974278	69882030	72126842	77192146
13	87.5	99.9	75000	95000	23252443	32941338	24672940	36387217
14	88.3	87.4	13459	13695	4213823	4154254	4471246	4588816
15	80.8	83.1	23257	22872	6663032	6597486	7070078	7287626
15 Cust Avg	74.7	77.6	40561	41176	11356116	11809269	12049864	13044596

Source: Table utilizes data from 1974 Load, Energy and Revenue Report.

FORECAST (1977) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mtnly Winter Off-Peak Period Energy
1	13.9	15.4	7500	7500	368497	402058	391009	444116
2	39.9	43.4	58000	60500	8204866	9104308	8706103	10056678
3	72.5	70.4	12000	10500	3081970	2565742	3270248	2834135
4	48.7	51.3	51833	51500	8937575	9167266	9483573	10126222
5	80.6	84.0	5850	5950	1671702	1735097	1773826	1916599
6	92.6	92.6	97167	97333	31876346	31282503	33823679	34554857
7	94.0	49.1	12167	9129	4054198	1554460	4301869	1717066
8	61.4	67.8	5283	5710	1150129	1342938	1220390	1483418
9	33.1	41.6	8100	8100	949748	1169983	1007768	1292370
10	95.9	95.0	21500	20000	7306790	6595347	7753164	7285263
11	77.6	72.5	5333	5717	1467116	1438681	1556642	1589177
12	86.5	87.7	247700	256917	75957253	78183547	80597499	86373103
13	62.0	86.1	87500	124167	19236980	37107867	20412171	40989592
14	84.1	85.1	19000	21833	5665655	6446546	6011772	7120896
15	78.7	81.7	23500	23500	6552895	6663057	6953213	7360058
15 Cust Avg	74.8	74.9	44162	47224	11765448	12984627	12484627	14342903

Source: Table utilizes Load Forecast 760209 data.

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GROWTH (1974-1977) DATA

Customer	Growth In Avg Mthly Non-Coinc Summer Peak Load	Growth In Avg Mthly Non-Coinc Winter Peak Load	Growth In Avg Mthly Summer Peak Period Energy	Growth In Avg Mthly Winter Peak Period Energy	Growth In Avg Mthly Summer Off-Peak Period Energy	Growth In Avg Mthly Winter Off-Peak Period Energy
1	1894	2039	-20135	-24628	-21365	-27205
2	24969	28403	3832873	3870509	4067024	4275389
3	736	320	202403	-62324	214768	-68844
4	6203	7065	795702	1095859	844311	1210493
5	376	599	91943	189428	97559	209242
6	414	-312	-538797	-42368	-571712	-46800
7	-22960	-8394	-3159518	-1635711	-3352534	-1805817
8	860	665	173939	150306	184564	166029
9	3704	3936	305909	483864	324597	534478
10	-3623	-4364	-1187811	-1348244	-1260375	-1489280
11	-256	605	46982	117758	49852	130077
12	23421	22216	7982975	8311517	8470657	9180957
13	12500	29167	-4015463	4155429	-4260769	4602375
14	5541	8138	1739112	2292292	1845356	2532000
15	243	628	-110137	65571	-116865	72432
Avg Growth For 15 Cust.	3601	6047	409332	1175357	434338	1298307

CASE 2

BASELINE (1974) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mthly Winter Off-Peak Period Energy
1	19.6	22.5	5606	5461	404338	444704	396688	453303
2	37.3	47.0	33031	32097	4548681	5454804	4462391	5560284
3	72.1	74.4	11264	10180	2995941	2739040	2939107	2792005
4	50.3	52.3	45630	44435	8470915	8412234	8310220	8574902
5	81.4	83.2	5474	5351	1643603	1610938	1612423	1642088
6	94.5	92.4	96753	97645	33725154	32647510	33085381	33278917
7	57.9	52.5	35127	17523	7505248	3324880	7362872	3389174
8	62.3	68.1	4423	5045	1015642	1242992	996375	1267028
9	41.3	47.5	4396	4164	669869	715092	657152	728928
10	95.4	93.9	25123	24364	8837898	8279021	8670242	8439113
11	71.7	74.4	5589	5112	1477526	1376701	1449497	1403322
12	85.5	85.8	224279	234702	70721359	72832903	69379762	74241274
13	87.5	99.9	75000	95000	24192157	34332335	23733227	34996220
14	88.3	87.4	13459	13695	4384119	4329674	4300951	4413397
15	80.8	83.1	23257	22872	6932309	6876074	6800801	7009037
15 Cust Avg	74.7	77.6	40561	41176	11834983	12307933	11610473	12545932

Source: Table utilizes data from 1974 Load, Energy and Revenue Report.

FORECAST (1977) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mthly Winter Off-Peak Period Energy
1	13.9	15.4	7500	7500	383390	419035	376117	427138
2	39.9	43.4	58000	60500	8536453	9488751	8374515	9672235
3	72.5	70.4	12000	10500	3206523	2674084	3145695	2725793
4	48.7	51.3	51833	51500	9298773	9554367	9122374	9739120
5	80.6	84.0	5850	5950	1739261	1808364	1706268	1843332
6	92.6	92.6	97167	97333	33164582	32603453	32535444	33233907
7	94.0	49.1	12167	9129	4218042	1620099	4138025	1651427
8	61.4	67.8	5283	5710	1196609	1399646	1173910	1426711
9	33.1	41.6	8100	8100	988130	1219387	969385	1242966
10	95.9	95.0	21500	20000	7602083	6873846	7457870	7006765
11	77.6	72.5	5333	5717	1526407	1499432	1497451	1528426
12	86.5	87.7	247700	256917	79026954	81495386	775527798	83071264
13	62.0	86.1	87500	124167	20014414	38674801	19634737	39422567
14	84.1	85.1	19000	21833	5894624	6718761	5782802	6848681
15	78.7	81.7	23500	23500	6817721	6944414	6688387	7078698
15 Cust Avg	74.8	74.9	44162	47224	12240931	13532922	12008719	13794602

Source: Table utilizes Load Forecast 760209 data.

GROWTH (1974-1977) DATA

Customer	Growth In Avg Mthly Non-Coinc Summer Peak Load	Growth In Avg Mthly Non-Coinc Winter Peak Load	Growth In Avg Mthly Summer Peak Period Energy	Growth In Avg Mthly Winter Peak Period Energy	Growth In Avg Mthly Summer Off-Peak Period Energy	Growth In Avg Mthly Winter Off-Peak Period Energy
1	1894	2039	-20948	-25669	-20571	-26165
2	24969	28403	3987772	4033947	3912124	411951
3	736	320	210582	-64956	206588	-66212
4	6203	7065	827858	1142133	812154	1164218
5	376	599	95658	197426	93845	201244
6	414	-312	-560572	-44157	-549937	-45010
7	-22960	-8394	-3287206	-1704781	-3224847	-1737747
8	860	665	180967	156654	177535	159688
9	3704	3936	318271	504295	312233	514046
10	-3623	-4364	-1235815	-1405175	-1212372	-1432348
11	-256	605	48881	122731	47954	125104
12	23421	22216	8305595	8662483	8148036	8829990
13	12500	29167	-4177743	4342466	-4098490	4426347
14	5541	8138	1510505	2389087	1481851	2435284
15	243	628	-114588	68340	-112414	69661
Avg Growth For 15 Cust.	3601	6047	405948	1224988	398246	1248678

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BASELINE (1974) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mthly Winter Off-Peak Period Energy
1	19.6	22.5	5606	5461	420410	462312	380597	435695
2	37.3	47.0	33031	32097	4729477	5670786	4281595	5344302
3	72.1	74.4	11264	10180	3115020	2847492	2820027	2683553
4	50.3	52.3	45630	44435	8807609	8745315	7973526	8241821
5	81.4	83.2	5474	5351	1708931	1674722	1547095	1578304
6	94.5	92.4	96753	97645	35065629	33940287	31744905	31986240
7	57.9	52.5	35127	17523	7803559	3456528	7064580	3257525
8	62.3	68.1	4423	5045	1056010	1292208	956006	1217812
9	41.3	47.5	4396	4164	696484	743406	630527	700606
10	95.4	93.9	25123	24364	9189179	8606828	8318961	8111306
11	71.7	74.4	5589	5112	1536254	1431211	1390770	1348812
12	85.5	85.8	224279	234701	73532326	75716710	66656895	71357466
13	87.5	99.9	75000	95000	25153724	35691718	22771660	33636836
14	88.3	87.4	13459	13695	4558374	4501106	4126695	4241964
15	80.8	83.1	23257	22872	7207847	7148331	6525262	6736780
15 Cust Avg	74.7	77.6	40561	41176	12305389	12795264	11140067	12058601

Source: Table utilizes data from 1974 Load, Energy and Revenue Report.

FORECAST (1977) DATA

Customer	Summer Load Factor	Winter Load Factor	Avg Mthly Non-Coinc Summer Peak Load	Avg Mthly Non-Coinc Winter Peak Load	Avg Mthly Summer Peak Period Energy	Avg Mthly Winter Peak Period Energy	Avg Mthly Summer Off-Peak Period Energy	Avg Mthly Winter Off-Peak Period Energy
1	13.9	15.4	7500	7500	398628	435627	360878	410547
2	39.9	43.4	58000	60500	8875752	9864457	8035216	9296530
3	72.5	70.4	12000	10500	3333973	2779964	3018245	2619913
4	48.7	51.3	51833	51500	9668372	9932671	8752775	9360817
5	80.6	84.0	5850	5950	1808391	1879966	1637136	1771730
6	92.6	92.6	97167	97333	34482777	33894382	31217249	31942978
7	94.0	49.1	12167	9129	4385697	1684247	3970370	1587279
8	61.4	67.8	5283	5710	1244171	1455064	1126348	1371292
9	33.1	41.6	8100	8100	1027406	1267668	930110	1194685
10	95.9	95.0	21500	20000	7904244	7146015	7155710	6734597
11	77.6	72.5	5333	5717	1587077	1558801	1436780	1469056
12	86.5	87.7	247700	256917	82168044	84722183	74386709	79844467
13	62.0	86.1	87500	124167	20809928	40206124	18839222	37891334
14	84.1	85.1	19000	21833	6128918	6984789	5548508	6582653
15	78.7	81.7	23500	23500	7088705	7219377	6417403	6803735
15 Cust Avg	74.8	74.9	44162	47224	12727472	14068756	11522177	13258774

Source: Table utilizes Load Forecast 760209 data.

GROWTH (1974-1977) DATA

Customer	Growth In Avg Mthly Non-Coinc Summer Peak Load	Growth In Avg Mthly Non-Coinc Winter Peak Load	Growth In Avg Mthly Summer Peak Period Energy	Growth In Avg Mthly Winter Peak Period Energy	Growth In Avg Mthly Summer Off-Peak Period Energy	Growth In Avg Mthly Winter Off-Peak Period Energy
1	1894	2039	-21782	-26685	-19719	-25148
2	24969	28403	4146275	4193671	3753621	3952228
3	736	320	218953	-67528	198218	-63650
4	6203	7065	860763	1187356	779249	1118996
5	376	599	99460	205244	90041	193426
6	414	-312	-582852	-45905	-527656	-43262
7	-22960	-8394	-3417862	-1772281	-3094210	-1670246
8	860	665	188161	162856	170342	153480
9	3704	3936	330922	524262	299583	494079
10	-3623	-4364	-1284935	-1460813	-1163251	-1376709
11	-256	605	50823	127590	46010	120244
12	23421	22216	8635718	9005473	7817914	8487001
13	12500	29167	-4343796	4514406	-3932438	4254498
14	5541	8138	1570544	2483683	1421813	2340689
15	243	628	-119142	71046	-107859	66955
Avg Growth For 15 Cust.	3601	6047	422083	1273492	382111	1200173

2. Baseline Peak Energy x Unit Costing Peak Energy Rate,

3. Baseline Off-Peak Energy x Unit Costing Off-Peak Energy Rate,

4. Load Growth x Marginal Demand Rate,

5. Peak Energy Growth x Marginal Peak Energy Rate, and

6. Off-Peak Energy Growth Rate x Marginal Off-Peak Energy Rate

As an illustration of a complete bill-calculation, customer 14 may be chosen. The average summer month, average winter month, and annual bills will be calculated using the Case 2 split between peak and off-peak energy usage.

Average Monthly Bill in Summer (1977)

1. Baseline Demand = 13,459 kW x $0.8633 = $11,619.15

2. Baseline Peak Energy = 4,384,119 kWh x $0.01162 = $50,943.45

3. Baseline Off-Peak Energy = 4,300,951 kWh x $0.00907 = $39,009.62

4. Demand Growth = 5,541 kW x $1.2967 = $7,185.01

5. Peak Energy Growth = 1,510,505 kWh = $27,189.09

6. Off-Peak Energy Growth = 1,481,851 kWh x $0.014 = $20,745.91

7. Average Summer Monthly Bill = $156,692.24

Average Monthly Bill in Winter (1977)

1. Baseline Demand = 13,695 kW x $5.1483 = $70,505.96

2. Baseline Peak Energy = 4,329,674 kWh x $0.01357 = $58,753.67

3. Baseline Off-Peak Energy = 4,413,397 kWh x $0.00907 = $40,029.51

4. Demand Growth = 8,138 kW x $7.7717 = $63,246.09

5. Peak Energy Growth = 2,389,087 kWh x $0.021 = $50,170.82

6. Off-Peak Energy Growth = 2,435,284 kWh x $0.014 = $34,093.97

7. Average Winter Monthly Bill = $316,800.02

Total Annual Bill (1977) = $(156,692.24 + 316,800.02) x 6 = $2,840,953.56

For comparative purposes, the following tables portray typical monthly summer, monthly winter, and annual bills for the fifteen selected customers. The bills have been calculated under six different pricing systems shown in Exhibit IV-3 of this volume.

All bills are calculated at rates reflecting 115 kV, firm power. Adjustments to rates due to different kV loads, interruptible power classes, or for any other reason, are excluded from the analysis. Any discounts or surcharges for these services are applicable under all pricing approaches, and, thus, would not change the comparative nature of the analysis.

The three cases which differentiate between peak and off-peak energy usage are only required for the two pricing systems which have seasonal time-of-day pricing.

2. Method of Calculation for Alternative Pricing-System

a. Bills Under Present Pricing-Methodology

1. Average 1977 Monthly Demand Rate x 1977 Monthly Non-Coincident Peak Demand, plus

2. Average 1977 Monthly Energy Rate x 1977 Monthly Energy Use

Multiply total by 12 to get annual bill.

b. Bills Using Marginal Costs Pro-Rated To Revenue Requirement

Calculation as in a, with only difference being in demand and energy rates. Under this method, a marginal-cost-determined demand/energy split suggests a lower demand and higher energy charge.

c. Seasonal Time-of-Day Bills Using Marginal Costs Pro-Rated to Revenue Requirement

1. Average 1977 Summer Demand Rate x 1977 Summer Non-Coincident Peak

2. Average 1977 Winter Demand Rate x 1977 Winter Non-Coincident Peak

3. Average 2977 Summer Peak Energy Rate x 1977 Summer Monthly Peak Energy x 6

4. Average 1977 Winter Peak Energy Rate x 1977 Winter Monthly Peak Energy x 6

5. Average 1977 Off-Peak Energy Rate x 1977 Off-Peak Energy x 12

Sum of 1-5 = total 1977 annual bill

3. Total Bill Analysis

The following analysis will examine each rate structure and how it diverges from the present rate structure and classes.

a. Present Rate Structure Classes Less Diversity

Removal of diversity increases all large-user bills. The relationship is: the higher the load factor, the lower the percentage increase from the present rate structure.

b. Present Rate Structure and Proposed Classes

All bills are higher than with the same rate structure and present classes.

c. Proposed Classes with Demand and Energy Based on Marginal Costs Pro-Rated to Revenue Requirement

This rate structure prices demand at a higher rate, and energy at a lower rate, than under the present pricing system. The result is that the low-load-factor customer pays more under the present pricing system. He may receive some relief on his kW bill through the use of interruptible power, but otherwise must pay a relatively high premium for kilowatts under the present system. An example of this is customer 1. Conversely, movement to the rate structure of this example suggests that the high load factor user, through his extensive use of energy, and little opportunity for higher load factors, would face a higher bill. An example of this situation is that faced by Customer 6.

COMPARATIVE 1977 AVERAGE SUMMER MONTHLY BILLS

Rate Structure Customer	Existing Rate Structure & Classes	Existing Rate Structure Classes Less Diversity	Existing Rate Structure & Proposed Classes	Proposed Classes With Demand & Energy Based on Marginal Costs Prorated to Revenue Requirements	Proposed Classes With Seasonal Time of Day Rates Based on Marginal Costs Prorated to Revenue Requirements			Seasonal Time of Day Bills Using Marginal Costs Where Marginal Use is Priced at Marginal Cost		
					Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
1	37,400	44,331	44,106	34,004	15,287	15,327	15,368	14,890	14,927	14,965
2	391,326	436,643	434,903	391,989	239,741	240,636	241,552	279,702	280,772	281,867
3	107,358	114,594	114,234	114,457	81,017	81,354	81,698	78,502	78,832	79,169
4	380,319	418,336	416,781	388,984	250,674	251,649	252,647	246,545	247,513	248,503
5	55,564	58,830	58,654	59,876	43,337	43,519	43,706	41,795	41,972	42,154
6	1,001,252	1,049,143	1,046,228	1,093,542	813,071	816,549	820,108	754,992	758,245	761,574
7	126,570	132,470	132,105	138,442	103,234	103,676	104,129	49,995	50,228	50,466
8	43,323	46,828	46,670	45,409	30,977	31,103	31,231	31,387	31,515	31,647
9	50,912	57,544	57,301	50,019	29,031	29,135	29,241	32,327	32,442	32,561
10	226,380	236,585	235,940	246,075	185,661	186,458	187,274	158,425	159,108	159,808
11	49,569	52,634	52,474	53,215	38,217	38,377	38,540	36,206	36,360	36,518
12	2,451,316	2,581,601	2,574,170	2,659,920	1,952,367	1,960,655	1,969,136	1,930,324	1,938,620	1,947,108
13	721,130	778,892	776,267	756,623	517,325	519,424	521,572	443,004	444,751	446,539
14	184,966	195,208	194,638	200,110	146,111	146,729	147,362	159,359	156,692	157,377
15	220,106	233,477	232,772	236,611	170,400	171,115	171,846	158,324	158,993	159,678

COMPARATIVE 1977 AVERAGE WINTER MONTHLY BILLS

Rate Structure Customer	Existing Rate Structure & Classes	Existing Rate Structure Classes Less Diversity	Existing Rate Structure & Proposed Classes	Proposed Classes With Demand & Energy Based on Marginal Costs Prorated to Revenue Requirements	Proposed Classes With Seasonal Time of Day Rates Based on Marginal Costs Prorated to Revenue Requirements			Seasonal Time of Day Bills Using Marginal Costs Where Marginal Use is Priced at Marginal Cost		
					Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
1	38,202	45,067	44,842	35,017	51,626	51,707	51,787	53,128	53,202	53,274
2	422,264	468,754	466,939	426,667	564,230	566,075	567,879	650,580	652,718	654,808
3	92,474	98,924	98,609	98,300	122,777	123,297	123,805	114,617	115,098	115,568
4	387,040	424,070	422,525	398,066	516,032	517,890	519,706	514,026	515,884	517,699
5	57,876	61,087	60,908	62,621	76,664	77,015	77,359	75,572	75,921	76,263
6	1,003,194	851,149	1,048,229	1,095,254	1,327,195	1,333,536	1,339,732	1,237,652	1,243,591	1,249,396
7	67,235	73,909	73,635	68,827	89,694	90,009	90,317	40,585	40,708	40,828
8	49,269	52,860	52,689	52,169	65,448	65,720	65,986	64,755	65,026	65,291
9	55,582	61,835	61,592	55,980	74,308	74,545	74,776	85,855	86,129	86,396
10	209,396	218,985	218,385	229,265	276,934	278,270	279,577	229,734	230,845	231,931
11	51,162	54,608	54,436	54,547	67,901	68,192	68,477	66,473	66,759	67,038
12	2,562,755	2,696,247	2,688,539	2,784,457	3,392,813	3,408,662	3,424,151	3,332,474	3,348,210	3,363,588
13	1,225,278	1,290,872	1,287,147	1,328,918	1,622,518	1,630,038	1,637,389	1,644,742	1,652,232	1,659,554
14	213,922	225,581	224,926	231,744	283,321	284,628	285,905	315,333	316,800	318,234
15	224,889	237,871	237,166	242,655	298,002	299,352	300,672	280,650	281,923	283,167

COMPARATIVE 1977 ANNUAL BILLS FOR LARGE USERS*

Rate Structure Customer	Existing Rate Structure & Classes	Existing Rate Structure Classes Less Diversity	Existing Rate Structure & Proposed Classes	Proposed Classes With Demand & Energy Based on Marginal Costs Prorated to Revenue Requirements	Proposed Classes With Seasonal Time of Day Rates Based on Marginal Costs Prorated to Revenue Requirements			Seasonal Time of Day Bills Using Marginal Costs Where Marginal Use is Priced at Marginal Cost		
					Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
1	453,612	536,388	533,688	414,126	401,474	402,205	402,929	408,111	408,774	409,433
2	4,881,540	5,432,382	5,411,052	4,911,936	4,823,826	4,840,270	4,856,587	5,581,690	5,600,942	5,620,053
3	1,198,992	1,281,108	1,277,058	1,276,542	1,222,768	1,227,906	1,233,020	1,158,716	1,163,578	1,168,421
4	4,604,154	5,054,436	5,035,836	4,722,300	4,600,238	4,617,237	4,634,120	4,563,431	4,580,383	4,597,217
5	680,640	719,502	717,372	734,982	720,000	723,205	726,387	704,197	707,362	710,503
6	12,026,676	11,401,752	12,566,742	13,132,776	12,841,596	12,900,509	12,959,043	11,955,859	12,011,018	12,605,822
7	1,162,830	1,238,274	1,234,440	1,243,614	1,157,568	1,162,113	1,166,677	543,479	545,611	547,758
8	555,552	598,128	596,154	585,468	578,550	580,936	583,302	576,849	579,248	581,627
9	638,964	716,274	713,358	635,994	620,031	622,075	624,102	709,092	711,427	713,741
10	2,614,656	2,733,420	2,725,950	2,852,040	2,775,567	2,788,371	2,801,105	2,328,954	2,339,720	2,350,430
11	604,386	643,452	641,460	646,572	636,703	639,413	642,106	616,074	618,718	621,334
12	30,084,426	31,667,088	31,576,254	32,666,262	32,071,082	32,215,904	32,359,722	31,576,793	31,720,980	31,864,179
13	11,678,448	12,418,584	12,380,484	12,513,246	12,839,058	12,896,775	12,953,770	12,526,477	12,581,898	12,636,557
14	2,395,328	2,524,734	2,517,384	2,591,124	2,576,593	2,588,142	2,599,600	2,848,153	2,840,954	2,853,663
15	2,669,970	2,828,008	2,819,628	2,875,596	2,810,409	2,822,802	2,835,111	2,633,847	2,645,498	2,657,070
Total For All 15 Customers	76,248,174	79,793,530	80,746,860	81,802,578	80,675,464	81,027,864	81,377,579	78,731,722	79,056,107	79,397,807

d. Seasonal and Time-of-Day Bills Using Marginal Costs Pro-Rated to the Revenue Requirement

This pricing-system reflects the varying costs involved in electricity use and rate of use during different seasons and time periods. Rates are higher for peak and winter energy consumption and demand, and correspondingly lower for off-peak and summer energy and demand. The differences between the bills in this pricing system, and those under the previous system in c, are generally not glaring, basically because of the assumptions used in splitting energy use from peak to off-peak. Actually, those customers who use considerable amounts of their energy during off-peak, or even summer peak hours, would notice a significant decrease in their bills in moving from a non-seasonal and non time-of-day structure, to a seasonal and time-of-day rate structure, as in this example. A good example of this is customer 7, who has more load during the less-expensive summer, as well as more than twice the amount of energy during off-peak and summer peak, than during winter peak. The result is a 6-7 per cent saving in his electricity bill. On the contrary, a customer, such as number 13, with more demand during the high-cost winter peak and with an even higher load factor during the winter, will face a larger bill, reflecting his demands upon the utility at times which are high-cost.

e. Seasonal Time-of-Day Bills Using Marginal Costs Where Marginal Use is Priced at Marginal Cost

The difference between this and the preceding example is the marginal-cost pricing of any changes, after a three-year time period, in customer load or energy. Thus the customer's behavioural pattern will react to rates reflecting the actual cost, or saving, to the utility of increasing or decreasing electricity service to the customer.

In an increasing-cost era, this would suggest that those customers experiencing growth would face higher bills under this pricing system. This is because actual marginal-cost based rates will be higher than in the previous example, where marginal cost based rates were pro-rated to equal a revenue requirement based on historical accounting costs. For example, under a pricing system which prices marginal cost at its additional cost to the electricity supplier, high growth customers, such as customers 2, 9, and 4, will have higher bills than in any other column. Of course, if the customer increases load or energy in summer or off-peak periods, the lower burden he imposes on the utility is reflected in lower rates during this season and time period. Customer 3, for example, has, from 1974 to 1977, a load increase in both summer and winter demand, with relatively more in the former. In addition, he increases relatively lower-cost summer peak energy and off-peak energy. The result is the lowest bill of any of the six pricing systems. The savings accruing to the customer are from two sources:

1. Where there was growth, the customer grew at less than the average rate.

2. The customer decreased usage of winter peak energy.

Perhaps the most impressive display of the savings possible to the customer through a decline in use and rate of use of electricity is observable in customer 7. This customer decreased usage in all periods, and because marginal savings in energy and capital for the utility are reflected in the rates, the large user has a substantially lower bill compared to other pricing systems. The customer's bill is 47 per cent of what it would be under the pricing methodology of the present system. It appears, therefore,

that in an era of high-cost energy, and high interest rates and capital construction costs, the incentive for the customer to conserve energy and power, and thus ease the utility's burden is greatest under a pricing system where marginal use is priced at marginal cost.

APPENDIX IV: Proposed Future Method of Establishing Customer-Related Costs and Dealing With Surplus Revenue

The processes of arranging cost groups for purposes of allocation are called classification and functionalization. Functionalization is the arrangement of costs according to functions, such as production and transmission. Classification is the arrangement of costs so that they may be allocated based on service characteristics, to which such costs are considered to be directly related. The principal service characteristics commonly used to allocate such costs include demand usage, energy consumption, and the number of customers served.

The maximum demand to be imposed on generating units, transmission lines, or distribution lines, determines to a great extent the size of these facilities, and thus, the amount of investment necessary for them. However, there is considerable variation between the sum of the maximum demands of the individual customers, and the maximum demand on the facility, due to the diversity which exists among the demands of various customers. In addition, although in general all investment and associated costs have a direct relationship with demand, that relation is non-linear for most of these cost elements. Fixed costs are thus demand-related only to the extent that demand is determinative of necessary plant investment, and of necessary expenses to insure service availability.

In general, transmission lines are designed to carry a specified maximum load, and the costs are therefore considered to be demand-related. In many respects, the distribution system represents an extension of the bulk transmission system, and hence, some of the plant items are reasonably classified as demand-related. On the other hand, there are elements of distribution which are clearly not identifiable with bulk supply, for example, such things as line transformers, services, and meters. Investment costs and expenses related to such facilities are more properly considered to be customer-related.

In the functionalization of costs of a typical electric system, only distribution plant and expenses, general plant, and material and supplies have any customer-related components of costs. There is no energy component save losses of distribution-related costs, therefore, we need consider only the demand and customer components.

A typical functionalization and classification of distribution plant would appear as in the accompanying table.

In regard to those accounts which are characterized as both demand- and customer-related, further analysis must be made to determine the portion represented by each relation. The fixed component of distribution facilities in the customer charge is that portion which is a function of the cost characteristics of the customer class. Recognizing that poles, conductors, transformers and meters are required to serve customers, regardless of their load requirements, the customer component is the theoretical minimum distribution system required to serve customers at nominal load conditions. The demand component recognizes the load requirement.

Two methods are available for determining the customer components of distribution facilities: an engineering model, or estimate, of the costs of a minimum system to supply service to the various classes of retail customers, a prospective method; and a statistical sampling of delivery facilities for the various customer classes, based on a current value statement of various sizes of equipment; or a combination of the two. Another approach might be trended current value of the functional accounts for the prospective annual work program.

The objective is to relate installed cost (of transformers, for example) to current carrying capacity or demand rating, create a curve for the various sizes of equipment involved using regression techniques, and extend the curve to the no-load intercept. The cost related to the zero-intercept load is the desired customer component, the balance being the variable portion which is added to the marginal cost of power. For those units such as conductors, which must be of a minimum size, in order to be safely constructed, the same type of curve may be generated and used to find the cost at the minimum safe size based on appropriate engineering standards. An analysis is necessary in order to determine the most appropriate method obtaining the relevant cost information.

Having established the fixed customer-related components of the distribution system, by customer class, and having established the avoidable customer costs, by customer classes, it is now possible to calculate the total marginal revenue, by customer classes. This is illustrated in the following table.

Functionalization and Classification of Distribution Plant		
Sub-station:		Demand
Distribution:	overhead primary	Demand/Customer
	overhead secondary	Demand/Customer
	underground primary	Demand/Customer
	underground secondary	Demand/Customer
	line transformers	Demand/Customer
Services:	overhead	Demand/Customer
	underground	Demand/Customer
Meters:		Customer
Street Lighting:		Customer
Customer Accounting:		Customer

Class	From Customer Charges		From Energy And Demand
	Fixed Component	Avoidable Component	
Year-Round Residential	$\$F_R$	$\$C_R$	$\$R_R$
Intermittent Occupancy	$\$F_{IO}$	$\$C_{IO}$	$\$R_{IO}$
General	$\$F_G$	$\$C_G$	$\$R_G$
Total Service Revenue	$\Sigma\$F$ +	$\Sigma\$C$ +	$\Sigma\$R$

The total revenue so calculated could then be compared with the revenue requirement, to determine the excess revenue by which the fixed component of the customer charges must be reduced. The monthly customer charge would be the sum of the residual avoidable cost component, and the residual fixed component, on a per-customer basis, per month.

If the amount of revenue to be folded back exceeds the total of the fixed component, then the marginal demand and energy common costs would be reduced, until the revenue matched the revenue requirement, and the customer charge would consist only of the avoidable customer costs.

The foregoing is illustrative of a methodology that could be used in the future for establishing the customer charges.

APPENDIX V: A Resource Cost-Benefit Analysis of Bulk Versus Individual Metering in Apartment Buildings in Ontario

A. BACKGROUND

Bulk metering implies the use of a single meter to measure the electrical consumption of an entire multi-unit building, rather than individual meters for each unit. The practice of master-metering electric service to apartments has been justified on the grounds of reduced operating and administrative costs. Having only one meter, one reading, and one bill for the sale of a large quantity of electricity can produce operating-savings. The potential for this type of saving increases with the number of apartment units in one building or complex.

Bulk metering of residential space in Ontario was relatively rare before the 1960s. Most electrical service to residences, either apartments or individual houses, was measured by means of an individual meter for each dwelling-unit. Although it is not clear just when or where bulk metering of residential customers began, some utilities evidently endorsed the concept as early as 1961. Since then most utilities have changed over to bulk metering or are in the process of doing so. At present, there are approximately 450,000 dwelling units in apartment buildings throughout Ontario converted, or originally designed, to accommodate bulk metering. This represents almost 82 per cent of the total number of apartment units in Ontario.[11]

Bulk metering has had some advantages for all parties. For the utility, the costs of installation, meter reading, billing, and collecting are reduced. For the landlord, the prevailing rate structure for utility services provides the opportunity to purchase the same amount of electricity as all the tenants would consume, only at a lower price, by acting as a single customer; this enables him to include electricity in the rental package, and attract potential tenants with the 'All Utilities Included' marketing-scheme. Under these circumstances, landlords may pass on some or all of the planned savings in electricity costs as reduced rental payments. The tenant, too, enjoys the added convenience of one monthly payment for rent and utility service.

On the surface the practice of bulk metering appears to benefit everyone concerned. However, when individual tenants face a zero marginal price for electricity, wasteful consumption may result. (Wasteful consumption merely refers to additional consumption which would not have occurred if the customer had faced the true cost consequences of his consumption decision.) With the recent emphasis on energy conservation, it is important to determine the extent of this inducement toward increased consumption. Studies dealing with this question have shown that tenants serviced with bulk metering do in fact consume considerably more electricity than those individually metered.

Midwest Research Institute conducted an extensive study for the U.S. Federal Energy Administration, to determine whether apartment or commercial tenants serviced with bulk meters tend to use more electricity than those with individual meters, and if so, how much more.[12]
The Institute did this by analysing matched pairs of apartment buildings in ten important urban areas throughout the United States. Matched pairs were chosen on the basis of geographic location; size and number of dwelling units; physical attributes of the building; degree of and type of heating, ventilation and air-conditioning; and occupant status.

Target cities in the final analysis included Los Angeles, New York, Chicago, Philadelphia, Detroit, San Francisco, Washington, D.C., Boston, Pittsburgh, and Houston. A total of 3,971 dwelling units were examined, and average annual consumption levels were compared.

It was found that, on the average, residential customers serviced with bulk meters consumed about 34 per cent more electricity than those with individual meters. In all situations examined, average consumption levels in bulk-metered units exceeded those in individually metered units. Additional consumption ranged from 204 kWh to as high as 4,756 kWh per annum. In complexes containing no electric heat or air-conditioning, the excess consumption was attributed to lighting and household appliance use.

Within Ontario Hydro a more modest study of the same type was also conducted.[13] The study included a sample of 48 apartment buildings in Hamilton and Metro Toronto, and was based on 1974 consumption levels. In order to minimize questionable comparisons, the sample excluded mixed commercial and residential structures, townhouses and other row-housing developments, and also electrically heated buildings. Over 2,000 dwelling-units, in buildings containing from 6 to 105 units, were included in the sample. In individually metered apartments, unoccupied suites were excluded from analysis and the common service consumption was pro-rated.

Average annual consumption levels were calculated for both bulk and individually metered dwelling-units and subjected to an analysis of variance. Results indicated that bulk-metered apartments as a group consumed 39.5 per cent more electricity than comparable apartments that were metered individually. On the average, the additional consumption amounted to 1,443 kWh per suite for 1974. When apartment buildings were disaggregated according to age, size, and suite distribution, a further analysis of variance confirmed additional consumption ranging from 791 kWh to as high as 1,939 kWh per suite. Only in one case - apartment buildings with fewer than 25 suites - was the difference between the two mean consumptions insignificant. Although electrically heated suites were excluded from analysis, it was estimated that their annual additional consumption might be as high as 5,385 kWh per suite.

On the basis of the above findings, it can be suggested that action should be taken to reverse the movement to bulk metering, as a measure to reduce the use of electricity. However, before such a move is contemplated, a comparison of the resource costs and resource savings associated with abandoning bulk metering should be made, in order to determine the overall net resource cost or benefit.

The next two sections of the report explain the basic approach and methodology employed as well as the various bases used for the calculations and conclusions presented.

B. APPROACH

The approach used throughout this report is a resource cost-benefit analysis. This technique is not to be confused with a full economic cost-benefit study, which attempts to determine and evaluate the social costs and social benefits of alternative policies.[14] The objective here is merely to identify and measure both the resource losses and the resource gains which society would incur if a particular policy in question were undertaken.

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[11]Municipal and Rural Services, Ontario Hydro
[12]Midwest Research Institute, *Energy Conservation Implications of Master Metering*, August, 1975. Midwest Research Institute (MRI) is an independent organization involved in energy and energy-conservation studies.
[13]*Comparative Analysis of Electricity Consumption in Bulk- And Individually-Metered Apartment Buildings*, Power Market Analysis, Report #75-9, (December, 1975).
[14]For an overview of economic cost-benefit analysis see E.J. Mishan, *Cost-Benefit Analysis*, (London, 1971).

The study does not consider such areas as the loss in consumer's surplus; the psychic benefits which a customer gains from knowing he does not have to pay for another's consumption with individual metering; or the reduction in external resource costs associated with reduced consumption. Estimates of these costs and benefits could not be developed given the time available and the acute lack of data. Such considerations should be taken into account in assessing the results of this study.

C. METHODOLOGY

1. Selection of Policy Options

The chief concern of this study, then, is to consider the feasibility of abandoning bulk metering of apartment suites in Ontario, within the framework of a resource cost-benefit analysis. Policy options under consideration include

1. *Policy Option A.* A continuation of the present method of measuring electrical consumption of an entire multi-unit building by means of a single bulk meter, and converting those buildings currently serviced with individual meters to bulk metering.

2. *Policy Option B.* Abandoning bulk metering in newly constructed buildings in favour of a single, individual meter for each suite, and converting all existing bulk-metered apartment buildings to individual metering.

3. *Policy Option C.* Abandoning bulk metering in newly constructed buildings in favour of a single, individual meter for each suite, and converting existing bulk-metered buildings to individual metering only where the cost of conversion justifies it.

Policy Option A is intended to reflect the current practice of measuring the electrical consumption of an entire building with a bulk meter. At present approximately 450,000 dwelling units in apartment buildings throughout Ontario have been converted, or were originally designed, to accommodate bulk metering. This represents almost 82 per cent of the total number of apartment rental units in Ontario. Assuming the trend towards bulk metering continues, it is estimated that by the end of 1977 the remaining individually metered buildings will have been converted to bulk metering.

The remaining policy options may be considered as possible alternatives to the present method. However, Policy Option B may be eliminated from the analysis for the following reason: In estimating conversion costs, from bulk to individual metering, a great deal of variation is encountered, depending on the characteristics of the building in question. Highest estimates are found for apartment buildings requiring substantial structural work and refinishing. Since conversion costs in these cases could run into thousands of dollars per suite, Policy Option B is not considered as a viable alternative.

2. Overview of Resource Costs and Resource Savings

The analysis is concerned with the benefits and costs associated with both policy options A and C in terms of actual physical resources. For reasons of convenience, all measurements are ultimately expressed in dollars.

A move to individual metering would yield two distinct resource-benefit streams as compared with bulk metering:

1. *Energy benefits*, which consist of the fuel and variable operation and maintenance expenses incurred by the generating-unit that provides energy.

2. *Capacity benefits*, associated with building and maintaining a system with sufficient capacity to meet all electrical demands placed on it.

On the cost side, such a move would mean higher operating and maintenance expenses, because of the increase in the number of meters installed each year as well as the additional costs of conversion. These additional resource costs may be grouped in the three categories Installation and Conversion; Reading, Billing, and Collecting; and Testing and Recalibration.

Figure 1 presents an overview of the cost-benefit analysis of bulk versus individual metering in the form of a flow chart. The upper portion shows the resource cost stream, the lower the resource benefit stream.

According to Figure 1, a movement to individual metering might be warranted if the total aggregate difference between the net cost and net saving were positive, or if an aggregate net benefit were realized. On the other hand, an aggregate net cost suggests that continued bulk metering might be warranted.

3. Period of Analysis

Selection of an appropriate time period for analysis was based on the following criteria:

1. A period beyond which dollar differences between alternatives will be insignificant when discounted to a present value.

2. A period beyond which forecasting inaccuracies will make estimated cost differences meaningless.

3. A period within which the majority of assets involved will reach the end of their useful lives.

The time period selected for the analysis is twenty-five years, 1976 to 2000 inclusive.

4. Data Collection

Data collection for the study was performed through correspondence with various departments in Ontario Hydro, utility companies, and electrical contractors. Since actual costs do vary from municipality to municipality, average estimates for all of Ontario are used for most computations.

A summary of the related costs associated with bulk and individually metered apartment buildings is shown in Table 1. Installation costs for both types of meters includes the actual meter plus any material and labour required. Clearly, installation costs will be minimized by installing a bulk meter for apartment buildings containing seven or more units. An apartment building containing 100 dwelling-units shows a saving of about $11,800.00 when serviced with a bulk meter rather than individual meters. Similarly, annual reading billing, and collecting costs are reduced by $930.64 for the same building. The larger the number of contained dwelling-units in an apartment building, the larger the annual savings in these cost categories. A more detailed description of these costs is provided in Section G.

Figure 1

OVERVIEW OF RESOURCE COST-BENEFIT ANALYSIS
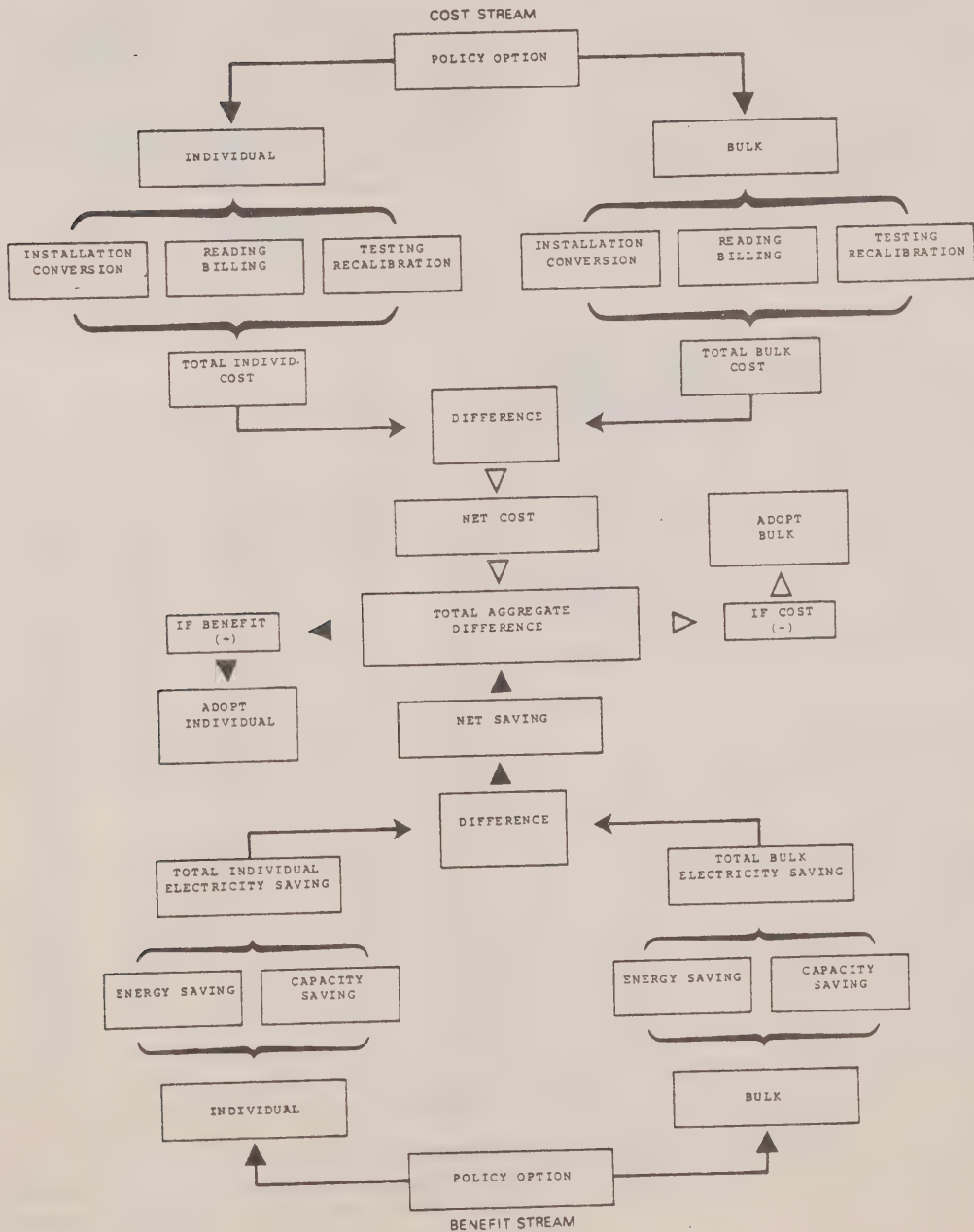
TABLE 1

Summary of Related Costs*

Individual

```
Installation per Suite.....................$127.00**
Annual Reading per Customer..................2.64
Annual Billing and Collecting
   per Customer................................6.90
Regular Testing and Recalibration
   per Meter..................................18.00
```

Bulk

```
Installation per Building.................$900.00
Annual Reading per Building.................10.56
Annual Billing and Collecting
   per Building.............................13.80
Regular Testing and Recalibration
   per Meter.................................32.00
```

```
*  Detailed costs are shown in addendum.
** Assumes additional wiring and labour
   totalling $50.00.
```

This report examines only self-contained rental dwelling units in separate structures originally designed as apartment buildings. Excluded from this category are suites in condominiums, structurally converted houses, flats, and row housing and other multiple dwellings. Restricting the analysis to apartment rental units is necessary because it is not clear just how many multiple dwellings in Ontario are bulk-metered.

According to estimates obtained from the Ministry of Housing, approximately 550,000 dwelling-units were located in 17,700 apartment structures throughout Ontario in 1975, as shown in Table 2. Two types of structures are distinguished: low-rise buildings, which consist of between 6 to 50 units; and high-rise buildings, consisting of 50 units or more. Although there were many more low-rise buildings than high-rise, in 1975 these buildings accounted for only 41 per cent of the total number of apartment rental units.

TABLE 2

Estimated Number of Rental Dwelling Units
In Ontario, 1975

Type of Structure*	Dwelling Units	Number of Structures
Single Family	200,000	200,000
Duplex	160,000	80,000
Other Multiple**	77,050	22,690
Low Rise Apartment (6-50 Units)	225,000	15,000
High Rise Apartments (50+ Units)	325,000	2,700
TOTAL	950,000	320,390

```
*  Excludes boarding and rooming houses
** Includes self-contained dwelling-units
   up to 5 units
```

Source: Ontario Ministry of Housing

About 82 per cent of the total number of apartment rental units were bulk metered in 1975. However, almost 20 per cent of these were electrically heated, and would therefore require substantial structural changes in order to convert to individual metering. Moreover, it is estimated that about 50,000 more dwelling-units at most would also require substantial changes for conversion. Adjusting the initial stock of dwelling-units for these two factors results in a total of 420,000 dwelling units, of which 320,000 are bulk metered. This figure is used as the initial stock of apartment dwelling-units throughout the analysis.

For the purpose of the present study, it was necessary to estimate both the number of apartment rental units and the number of apartment structures in Ontario for each year up to and including 2000. These estimates are shown in Table 3. A brief discussion of the methodology employed is provided in Section G.

TABLE 3

ESTIMATED NUMBER OF APARTMENT RENTAL UNITS IN ONTARIO
1976-2000
'000

Year	Annual Increase In Total Housing Stock	Apartment Rental Units	Annual Increase	Occupied Rental Units *
1976	90	570	20	558.6
1977	90	590	20	578.2
1978	90	610	20	597.8
1979	90	630	20	617.4
1980	90	650	20	637.0
1981	90	665	15	648.4
1982	90	680	15	663.0
1983	90	695	15	677.6
1984	90	710	15	692.3
1985	90	725	15	706.9
1986	70	743	18	728.1
1987	70	761	18	745.8
1988	70	779	18	763.4
1989	70	797	18	781.1
1990	70	815	18	798.7
1991	75	835	20	818.3
1992	75	855	20	837.9
1993	75	875	20	857.5
1994	85	895	20	877.1
1995	85	915	20	896.7
1996	85	935	20	916.3
1997	85	955	20	935.9
1998	85	975	20	855.5
1999	85	995	20	975.1
2000	85	1015	20	994.7

```
* Assumes 2.5 per cent vacancy rate between 1981 and
  1985 and 2.0 per cent for all other years.
```

5. Consumption Levels

During the period of analysis, it is assumed that tenants in bulk-metered buildings with non-electric heating would consume, on

Figure 1A

OVERVIEW OF RESOURCE COST-BENEFIT ANALYSIS

COST STREAM

POLICY OPTION

INDIVIDUAL — BULK

INSTALLATION CONVERSION $72M | READING BILLING $73M | TESTING RECALIBRATION $8M

INSTALLATION CONVERSION $6M | READING BILLING $8M | TESTING RECALIBRATION $2M

TOTAL INDIVID. COST $152M

TOTAL BULK COST $16M

DIFFERENCE $136M

NET COST $136M

ADOPT BULK

IF BENEFIT (+)

TOTAL AGGREGATE DIFFERENCE $166M - $136

IF COST (-)

ADOPT INDIVIDUAL $30M

NET SAVING $166M

DIFFERENCE $166M

TOTAL INDIVIDUAL ELECTRICITY SAVING $143M

TOTAL BULK ELECTRICITY SAVING - $23M

ENERGY SAVING $119M | CAPACITY SAVING $24M

ENERGY SAVING - $21M | CAPACITY SAVING - $2M

INDIVIDUAL

BULK

POLICY OPTION

BENEFIT STREAM

the average, 1443 kWh more electricity per annum than those individually metered. Although average residential consumption will more than likely increase over time, additional consumption was assumed to remain constant. It was further assumed that additional consumption in electrically heated apartment buildings would be about 3,853 kWh per annum, representing an increase of 39 per cent compared to individually metered buildings. Compared to additional consumption in buildings with non-electric heating, the difference of 2,410 kWh is attributed to excess heating and, again is assumed to remain constant over time. Mean consumption levels in bulk and individually metered apartment buildings are shown in Table 4.

TABLE 4

Annual Mean Consumption Levels in Bulk- and Individually-Metered Buildings

kWh

	Non-Electrically* Heated	Electrically Heated
Bulk	5,092	13,616**
Individual	3,649	9,763
Difference	1,443	3,853
% Difference	39	39

* Source: Power Market Analysis, Ontario Hydro
** Adjusted for water heating (5,400 kWh in 1974)

6. Escalation and Discount Rates

In order to compare future streams of benefits and costs at a common point in time, one must first consider expected future payments for goods and services used in achieving the required result under both policy options, and then convert these estimates to equivalent values at a common date by means of a discount rate. Accordingly, escalation rates[15] reflecting anticipated levels of wages and prices are applied to all future values, and these in turn are discounted to obtain the present value of each cost and benefit stream. Several discount rates are used, ranging from 5 to 15 per cent, in order to provide a measure of the sensitivity of the final results to the rate.

D. PRESENTATION OF RESULTS

Figure 1A is a reproduction of Figure 1, with computed estimates for the various components shown in parentheses. The total aggregate resource benefit is shown in the centre. All estimates are based on a discount rate of 12 per cent.

1. Operating and Maintenance Costs

The present value of operating and maintenance costs for each policy option is shown in Table 5 under columns 1 and 2.

Negative values shown in the final year reflect terminal values associated with meters which still have an economic life. In other words, a meter installed in the year 1990 with an economic life of 25 years has 15 years of service beyond the period of analysis. A value for the remaining life of all meters must therefore be calculated, and included as a retained asset in the final year of analysis.

TABLE 5

Present Value of Operating and Maintenance Costs for Year Shown

$'Million

Year	(1) Individual	(2) Bulk	(3) Net Cost (Individual-Bulk)
1976	9.529	3.995	5.534
1977	12.480	2.804	9.676
1978	14.825	.648	14.177
1979	15.287	.638	14.649
1980	19.343	.636	18.707
1981	6.132	.575	5.557
1982	5.982	.654	5.328
1983	5.837	.595	5.242
1984	5.686	.509	5.177
1985	5.571	.485	5.086
1986	4.950	.479	4.471
1987	4.790	.455	4.335
1988	4.639	.486	4.153
1989	4.465	.460	4.005
1990	4.318	.392	3.926
1991	3.993	.375	3.618
1992	3.852	.358	3.494
1993	3.717	.340	3.377
1994	3.593	.360	3.233
1995	3.467	.342	3.125
1996	3.343	.293	3.050
1997	2.978	.248	2.730
1998	2.777	.236	2.541
1999	2.679	.223	2.451
2000	(2.439)	(.660)	(1.779)
TOTAL	151.790	15.926	135.864

Annual net-cost differences between individual and bulk metering are shown in column 3. For all years except 2000, costs are substantially lower for bulk metering than for individual. A change to individual-metering would mean an additional resource cost of approximately $136 million over the next twenty-five years, 46 per cent of which is incurred within the first five years.

Column 3 of Table 5 has been disaggregated into the various cost components and shown graphically in Figure 2. Although net installation costs are by far the most significant during the period of conversion, they decline to average approximately $1.0 million during the remaining period of analysis. On the other hand, net reading, billing, and collecting-costs are more pronounced after the conversion period, becoming the most significant cost category. These costs average over $2.5 million throughout the same period. Net costs for testing and recalibration are the least significant, averaging less than a quarter of a million dollars per annum, and totalling only $6.1 million for the entire period.

FIGURE 2

PRESENT NET WORTH OF OPERATING AND
MAINTENANCE COSTS
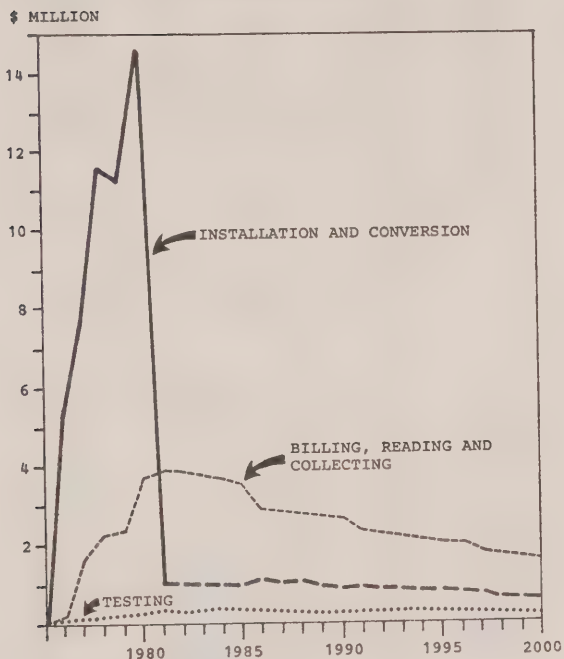
2. Consumption Levels

The total amount of additional consumption attributable to bulk metering is shown in Table 6. Three main sources are distinguished. Additional consumption resulting from the conversion of 100,000 individually metered suites to bulk metering is shown under column 1. It was assumed that tenants in this category would increase their consumption levels by 1443 kWh with such a move. By the end of the century, there would be over 3 billion kWh of additional consumption.

TABLE 6

Incremental Annual Electricity Consumption
Resulting from Bulk Metering

'Million kWh

Year	(1) Conversion to Bulk	(2) Domestic Component	(3) Heating Component	(4) Total
1976	35.40	56.56	8.27	100.23
1977	106.10	169.69	24.80	300.59
1978	141.40	282.82	41.34	465.56
1979	141.40	395.95	57.87	595.22
1980	141.40	523.23	74.40	739.03
1981	140.70	601.46	88.41	830.57
1982	140.70	622.56	100.75	864.01
1983	140.70	643.67	113.08	897.45
1984	140.70	664.77	125.42	930.89
1985	140.70	685.87	137.46	964.03
1986	141.40	712.73	152.10	1,006.23
1987	141.40	738.18	166.98	1,046.56
1988	141.40	763.64	181.86	1,086.90
1989	141.40	789.09	196.74	1,127.23
1990	141.40	814.55	211.62	1,167.57
1991	141.40	841.41	227.33	1,210.14
1992	141.40	869.69	243.86	1,254.95
1993	141.40	897.98	260.39	1,299.77
1994	141.40	926.26	276.92	1,344.58
1995	141.40	954.54	293.46	1,389.40
1996	141.40	982.83	309.99	1,434.22
1997	141.40	1,011.11	326.52	1,479.03
1998	141.40	1,039.39	343.06	1,523.85
1999	141.40	1,067.67	359.59	1,568.66
2000	141.40	1,095.96	376.12	1,613.48
TOTAL	3,248.50	18,151.61	4,698.34	26,240.15

Column 2 of the same table shows the amount of additional electricity consumption associated with the domestic component of all tenants. This portion, totalling 18 billion kWh for the 25-year period, accounts for almost 70 per cent of all additional consumption. New tenants alone will consume, on the average, an additional 25 million kWh each year for the next twenty-five years.

The amount of electricity consumption attributable to tenants with electric space heating is shown under column 3. It was assumed that approximately 35 per cent of all new buildings would be electrically heated throughout the period of analysis and that annual additional consumption attributable to electric heating alone would average 2410 kWh per suite. In total, this category of customers would consume over 4.5 billion kWh, accounting for almost 18 per cent of the total additional consumption attributable to bulk metering. By the turn of the century, annual additional consumption from all sources will total approximately 26.2 billion kWh.

Clearly, the magnitude of resource benefits that may be attributable to individual metering is substantial, and should therefore be compared with the relevant net operating and maintenance costs of adopting such a move. However, before any such comparison can be made it is necessary to translate kWh savings into dollar savings.

For the purpose of this report, additional consumption is viewed as the potential resource savings available. A customer living in an apartment with bulk metering is not aware of the cost consequences of the last kilowatt-hour of electricity he consumes, since the electricity bill is included in his rent. The customer is given the incentive to use as much electricity as he desires, because in the short run there is no cost attached to the additional consumption.

However, there are costs associated with producing more electricity. Having to provide for additional consumption imposes further demands on scarce resources such as capital and primary energy. Insofar as this higher consumption would not occur if the price the customer faced were related to the cost of production, additional consumption may be viewed as potential resource savings available. Since various inputs contribute to the production of additional consumption, the dollar value of these inputs is used to measure the value of the energy savings that would result from individual metering. Once the value of these resources is determined, it may then be compared with the net resource cost component to determine the aggregate net benefit or cost.

Two major input components associated with producing electrical energy are distinguished. The first, capacity cost, is the cost associated with building and maintaining a system with enough capacity to meet all electrical demands placed on it. The second, energy cost, is the cost of producing the power demanded. These latter costs consist of the fuel and variable operation and maintenance expenses incurred by the generating-unit that provides the energy.

A summary of the present value of potential benefits is provided in Table 7 and graphically in Figure 3. Further analysis of the derivation of these values is outlined in Section G.

FIGURE 3

PRESENT NET VALUE OF ENERGY AND
CAPACITY SAVINGS
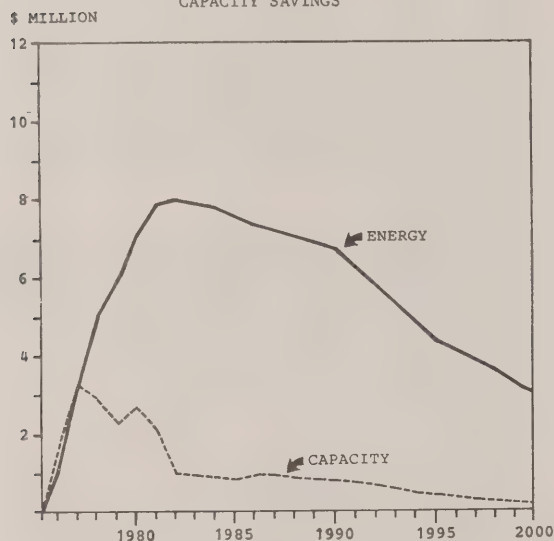
TABLE 7

Present Value of Potential Conservation
Benefits in Year Shown

$'Million

| | (1) | (2) | (3) | (4) |
Year	Energy	Capacity	Total	Cumulative Total
1976	1.083	1.763	2.846	2.846
1977	3.300	3.431	6.731	9.577
1978	4.984	2.919	7.903	17.480
1979	5.852	2.371	8.223	25.703
1980	7.116	2.574	9.690	35.393
1981	7.751	1.999	9.750	45.143
1982	7.895	1.000	8.895	54.038
1983	7.739	.868	8.606	62.644
1984	7.637	.842	8.479	71.123
1985	7.527	.796	8.322	79.445
1986	7.385	.937	8.323	87.768
1987	7.221	.859	8.080	95.848
1988	7.047	.808	7.855	103.703
1989	6.871	.738	7.609	111.312
1990	6.689	.670	7.359	118.671
1991	6.171	.631	6.803	125.474
1992	5.677	.573	6.250	131.724
1993	5.197	.506	5.702	137.426
1994	4.730	.452	5.182	142.608
1995	4.279	.385	4.664	147.272
1996	4.037	.320	4.357	151.629
1997	3.799	.254	4.053	155.682
1998	3.570	.189	3.759	159.441
1999	3.347	.124	3.471	162.912
2000	3.131	.061	3.192	166.104
TOTAL NET WORTH	140.035	26.069	166.104	***

TABLE 8

Annual Aggregate Net Resource Benefits*
$'Millions

| | (1) | (2) | (3) | (4) |
Year	Cost	Savings	Aggregate Benefit	Cumulative Benefit
1976	5.534	2.846	(2.688)	(2.688)
1977	9.676	6.731	(2.945)	(5.633)
1978	14.177	7.903	(6.274)	(11.907)
1979	14.649	8.223	(6.426)	(18.333)
1980	18.707	9.690	(9.017)	(27.350)
1981	5.557	9.750	4.193	(23.157)
1982	5.328	8.895	3.567	(19.590)
1983	5.242	8.606	3.364	(16.226)
1984	5.177	8.479	3.302	(12.924)
1985	5.086	8.322	3.236	(9.688)
1986	4.471	8.323	3.852	(5.836)
1987	4.335	8.080	3.745	(2.091)
1988	4.153	7.855	3.702	1.611
1989	4.005	7.609	3.604	5.215
1990	3.926	7.359	3.433	8.648
1991	3.618	6.803	3.185	11.833
1992	3.494	6.250	2.756	14.589
1993	3.377	5.702	2.325	16.914
1994	3.233	5.182	1.949	18.863
1995	3.125	4.664	1.539	20.402
1996	3.050	4.357	1.307	21.709
1997	2.730	4.053	1.323	23.032
1998	2.541	3.759	1.218	24.250
1999	2.456	3.471	1.015	25.265
2000	(1.779)	3.192	4.971	30.236
TOTAL	135.868	166.104	30.236	

* Aggregate costs are denoted by brackets.

Annual energy and capacity savings attributable to individual metering are shown separately in columns 1 and 2 respectively, while columns 3 and 4 show annual as well as cumulative totals for the period of analysis. Although capacity savings are comparatively larger than energy savings during the first two years, the latter are by far more significant during the remaining 23 years. Of the total savings of $166.1 million, the energy component accounts for over 80 per cent. Total annual savings average $6.6 million.

3. Aggregate Resource Benefits and Costs

A comparison of annual aggregate costs and benefits associated with individual metering is shown in Table 8 and graphically in Figure 4. As one might have expected, the period from 1976

to 1980 is characterized by an aggregate net cost totalling $27.4 million, most of which is attributable to converting buildings from bulk to individual metering.

FIGURE 4
SUMMARY OF NET RESOURCE BENEFITS
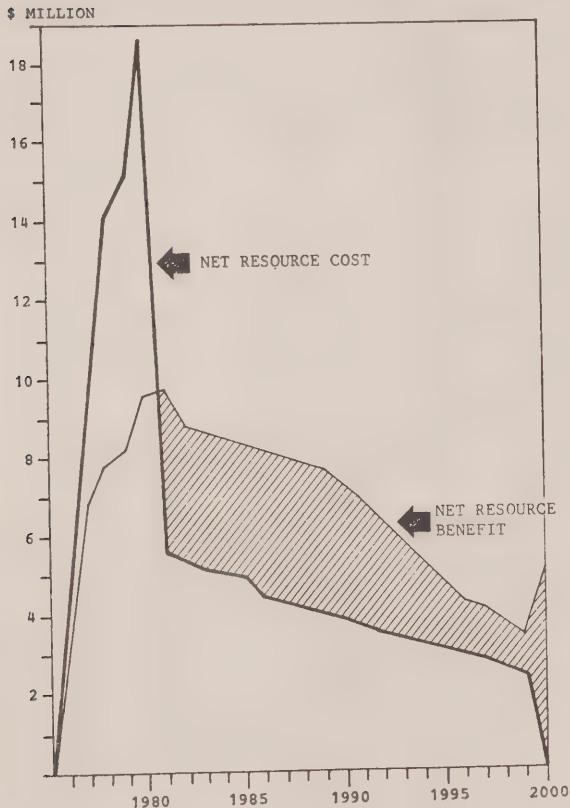
After 1980, and for the remaining period of analysis, aggregate benefits are realized, averaging $2.9 million per annum. However, not until 1988 are these benefits enough to outweigh the cost of conversion, as shown in column 4. When compared with the total net cost of $135.9 million, total savings account for an aggregate benefit of $30.2 million. In other words, if all municipalities had endorsed individual metering beginning in January 1976, aggregate resource benefits amounting to approximately $30 million would have been realized by the turn of the century.

4. Sensitivity Analysis

Sensitivity analysis is a technique used to identify those estimates having the greatest impact on the final outcome. Owing to the large number of necessary assumptions and forecasts required throughout this study, a sensitivity analysis has not been applied to all cost and saving components separately. Instead, estimates have been grouped under general categories, and those having the greatest effect on present value are identified by inspection. These results are summarized in Table 9.

Entries under the first column of Table 9 indicate the effects of a change of one per cent in various cost and saving components as a percentage of the aggregate benefit. For example, underestimating installation costs for individual meters by one per cent, all other things remaining constant, will mean that aggregate benefits have been overestimated by 2.4 per cent. Simiarly, a one-per-cent overestimate of energy savings means a 4.0-per-cent overestimate of benefits. The figure in parentheses corresponding to the percentage change in aggregate benefits is interpreted as a measure of the level of importance for each category listed.

For example, a value of 1 implies that a 10-per-cent change in a given category results in a 10-per-cent change in aggregate benefits. A value less than one means that a 10-per-cent change in a given category changes aggregate benefits by more than 10 per cent, while a value greater than one means that a 10-per-cent change alters the final outcome by less than 10 per cent. A cost or savings category has a significant, moderate, or insignificant effect on aggregate benefits whenever the value in parenthesis is less than, equal to, or greater than one. The closer the value is to zero, the more significant the relative impact; and similarly as the value increases beyond one, the less significant the impact on aggregate benefits.

Based on the above criteria, those categories which may be considered significant include installation, reading, billing and collecting costs, and energy savings related to individual metering. As expected, changes in testing and recalibration have a minor effect on aggregate benefits, while capacity savings have a moderate impact. All categories affecting bulk metering may be considered as having insignificant impacts on aggregate benefits.

Column 2 of the same table shows the magnitude of percentage change required to reduce aggregate benefits to zero. As is indicated, most categories require substantial changes to reduce aggregate benefits to zero.

Seeing that operating and maintenance costs for individual metering were in all likelihood overestimated at the start, while associated energy and capacity savings were underestimated, results of the sensitivity analysis confirm that net resource benefits would result from a move to individual metering.

Table 10 summarizes the results obtained when the benefit and cost stream are discounted for a range of discount rates ranging from 5 to 15 per cent. As one would expect, the present value of net benefits associated with a move to individual metering increases dramatically with decreases in the discount rate. However, a net benefit is realized in all cases as the values in row 3 show.

Values shown in row 5 under the various discount rates indicate the estimated net conversion cost for the period 1976 to 1980 inclusive, during which time approximately 320,000 dwelling-units will have been converted to individual metering. The costs are "net" in that the associated savings attributable to reduced consumption levels have been taken into account. Again, as one would expect, the present value of net conversion costs

Table 9

SUMMARY OF SENSITIVITY ANALYSIS

	One Per Cent Increase * (1)			Required Change for Aggregate Benefit =0 (2)		
	Individual	Bulk %	Both**	Individual	Bulk %	Both
Installation #	-2.4 (.4)	+.2 (5.0)	-2.2 (.5)	+42.0	-505.1	+46.1
Reading, Billing Collecting	-2.4 (.4)	+.3 (3.3)	-2.2 (.5)	+41.0	-356.9	+46.3
Testing, Recalibration	-.3 (3.3)	+.1 (10.0)	-.2 (5.0)	+387.8	-1821.5	+500.0
Energy	+4.0 (.3)	+.7 (1.4)	+4.7 (.2)	-25.2	-142.5	-21.4
Capacity	+.8 (1.3)	+.1 (10.0)	+.9 (1.1)	-124.1	-1428.5	-114.6

* Measures the effect on the aggregate benefit.
For example: A 1% underestimate in the cost of testing individual
meters results in a .3% decrease in aggreate benefits
1% underestimate = $.77 million for 25 year period
so that $\frac{.77}{29.88} \simeq .003$ or .3%

** Changing individual and bulk by 1% simultaneously and
in the same direction

\# Includes conversion period, 1976-1981.

TABLE 10

Summary of Present-Value Calculations

$'Million

	(1) 5%	(2) 10%	(3) 12%	(4) 15%
(1) Benefit Stream	489.0	221.8	166.0	117.2
(2) Cost Stream	265.4	161.4	136.0	110.0
(3) Net Benefit	223.6	60.4	30.0	7.2
(4) Break-Even Year*	1976	1985	1988	1995
(5) Net Conversion Cost**	(26.1)	20.2	27.4	30.8

* Indicates the year in which the cumulative cost stream is equal to the cumulative benefit stream, so that the net cumulative benefit is equal to zero.

** Covers the period 1976 to 1980 inclusive, and indicates the actual cost of conversion. The value in brackets for a discount rate of 5 per cent implies a net benefit (a negative net conversion cost).

varies directly with the discount rate used. However, it is interesting to note that there is a $26.1-million net benefit, instead of a net cost when a discount rate of 5 per cent is applied.

The year shown under the various discount rates in row 4 of Table 10 is the year when the cumulative net benefit (see column 4 of Table 10) is greater than zero. For example, assuming a discount rate of 10 per cent (column 2 of Table 10), a move to individual metering results in a net benefit of approximately $60.4 million, over the 25-year period. Related benefit and cost streams amount to $221.8 and $161.4 million, respectively. Moreover, the conversion period is characterized by a net cost of $20.2 million. However, by 1985, subsequent annual net benefits of over $20.2 million would be realized, so that the cumulative net benefit would be positive. Hence, 1985 may be interpreted to be the break-even year. In this particular study, higher discount rates are associated with break-even years which occur in the later stages of the period of analysis.

In a cost-benefit evaluation, a high discount rate places greater emphasis on the near-term costs or benefits. On the other hand, a low discount rate places greater emphasis on the long-term effects.

It is difficult to ascertain precisely which discount rate is the most appropriate. The maximum rate used in this study is 12 per cent. Since the value of net benefit varies inversely with the discount rate used, final results may be considered to represent a minimum attainable net benefit. In other words, a move to individual metering as outlined in this report could result in a net benefit as high as $224 million, over the period of analysis, if a rate of 5 per cent is chosen. Moreover, the minimum attainable resource benefit should not be less than $30 million.

E. CONCLUSION

In Section D of this report, it was shown that a move to individual metering would mean an increase of approximately $136 million in operating and maintenance costs over the next 25 years. However, conservative estimates of resource benefits are in the area of $166 million for the same period. Thus, an aggregate resource benefit of at least $30 million can be realized by such a move. In terms of actual kWh consumption, resource savings benefits would amount to over 26 billion kWh's by the turn of the century.

The results of this report indicate that Ontario as a whole would benefit, in terms of resource savings, from the adoption of individual metering as a means for measuring electrical consumption in apartment buildings.

Throughout the entire analysis, considerable variation was encountered in determining the dollar value of various cost and benefit components, for both individually and bulk-metered customers. In many circumstances, a small variation in these categories may dramatically affect the outcome. To avoid any questionable comparisons stemming from such variation, all cost and benefit estimates were purposely biased in favour of the bulk-metering policy option. Taking this into account, one may view the final results as the minimum aggregate resource benefits attainable.

F. RECOMMENDATIONS

Based on the findings of this resource cost-benefit report, it is suggested that the following recommendations may be appropriate:

1. *The current practice of converting individually metered apartments to bulk metering should be discontinued.*

2. *The current practice of bulk metering new apartment buildings should cease, and individual meters should be installed for each separate dwelling-unit.*

3. *Apartment buildings originally designed for individual meters and now serviced with bulk meters should be reconverted to individual meters for each dwelling-unit.*

4. *The metering status of the remaining apartment buildings, originally designed to accommodate bulk metering, and requiring structural changes, should be determined from cost-benefit analyses conducted by the appropriate municipalities.*

G. ADDENDUM

The following addendum presents the details of all calculations and related assumptions used in the preceding analysis. Four subsections are included:

1. Cost Considerations,
2. Benefit Considerations,
3. Apartment Building Data, and
4. Classification of Customers.

1. Cost Considerations

Costs have been grouped in the following three categories and calculated using 1975 market prices: meter reading, customer billing and collecting; annual testing and recalibration; and conversion, that is, labour, installation and associated materials.

Since actual costs vary from municipality to municipality, average estimates for all of Ontario were used in most computations. In preparing estimates of costs, it was necessary to consider expected future payments for resources, acquired in the process of achieving the required result, under both policies. Accordingly, escalation indices, reflecting anticipated levels of wages and prices, were applied to all future values. A composite rate, composed of labour and material, was used for these calculations, as shown in Table A1. Since escalation, resulting from changes in productivity and improved work methods, were not included in future payments, estimates of future costs are more than likely over-stated, although it is difficult to determine the precise magnitude of the over-statement.

TABLE A1

Escalation Index
1975-2000

Year	Labour	Material	Composite*
	(Percentage of Base Year 1975 = 100)		
1975	100	100	100
1976	109	109	109
1977	118	120	119
1978	128	133	131
1979	142	150	146
1980	157	166	162
1981	171	179	175
1982	184	192	188
1983	197	204	201
1984	212	217	215
1985	230	232	231
1986	246	244	245
1987	263	256	260
1988	282	269	276
1989	301	283	292
1990	322	297	310
1991	345	311	328
1992	369	327	348
1993	395	343	369
1994	423	361	392
1995	452	379	416
1996	484	397	441
1997	518	417	468
1998	554	438	496
1999	593	460	527
2000	634	483	559

* Composed of 50 per cent Labour and 50 per cent Material

Source: Economic Forecasting Series, Office of the Chief Economist, February 20, 1976.

a. Reading, Billing, and Collecting

Table A2 shows a detailed account of the reading, billing, and collecting costs associated with individual and bulk-metered customers. Annual meter-reading costs for the latter customers were based on one reading per month, and assumed to be constant throughout the period of analysis. In the case of individually-metered customers, annual meter-reading costs were initially based on six readings per year, and subsequently reduced to five in 1986, and to 4.5 in 1991, in order to reflect an anticipated trend toward fewer readings for residential customers.

TABLE A2

Estimated Reading, Billing and Collecting Cost

Meter Reading

  (i) Four dials and check..................$ .44

Customer Billing and Collecting (Per Bill)

    (i) Clerical............................$ .25
   (ii) Stationary and Postage............... .11
  (iii) Processing........................... .50
   (iv) Banking Charge....................... .19
    (v) Readjustments........................ .10

(A) Individual Reading

    (i) Meter Reading........................$ .44
   (ii) Annual Reading....................... 2.64
  (iii) Billing and Collecting............... 1.15
   (iv) Annual Billing and Collecting........ 6.90
    (v) Annual Reading, Billing and
        Collecting........................... 9.54

(B) Bulk Customer

    (i) Meter Reading (2 meters @ $0.44).....$ .88
   (ii) Annual Reading....................... 10.56
  (iii) Billing and Collecting............... 1.15
   (iv) Annual Billing and Collecting........ 13.80
    (v) Annual Reading, Billing and
        Collecting........................... 24.36

Although a re-adjustment charge was included in the billing and collecting procedure, costs associated with 'bad debts' were excluded, for both individual and bulk metered customers, primarily because these costs may be regarded as distributional, and hence, should not be included as a net cost or benefit. For example, consider the case of an apartment building serviced with a bulk meter. For one reason or another, a particular tenant decides not to pay his monthly rent, which includes his utility bill. Since the landlord collects the monthly rent, and is responsible for the electricity bill, the landlord will incur the loss.

Now, assume that the same building is converted to individual metering. A tenant decides not to pay his monthly rent, nor his utility bill. Under these circumstances, both the municipality and the landlord will incur a loss: the landlord loses the rent, and the municipality the amount of the utility bill. This would happen unless the utility could trace the defaulting tenant, and collect the account through an action in the small claims court.

Under both circumstances, a loss in revenue occurs, the only difference being that, in one case, the landlord incurs the full loss of revenue, while in the other case, both the landlord and the municipality share the loss. Generally, the net cost or benefit (excluding the distributional aspect) associated with "bad debts", under bulk and individual metering, should be zero, as long as the tenant reacts in the same way, in both situations. However, it could be argued that the incidence of "bad debts" would be higher with individually-metered customers than with bulk-metered customers or vice-versa.

b. Testing and Recalibration

Table A3 presents a summary of the costs associated with the

testing and recalibration of both individual and bulk meters. Government regulation requires that bulk meters be tested every six years, in order to meet approved standards. On the other hand, the reliability of conventional individual meters has been well established by very extensive use over a number of years. This permits a statistical sampling procedure to be used, to reduce the amount of testing required. Generally, meters are installed in "lots" of 10,000 and after eight years of use, samples of 200 meters are tested every two years. Whenever an unsatisfactory sample is found, the entire lot of 10,000 meters is recalibrated and re-installed for another eight-year period.

TABLE A3

Estimated Testing and Recalibration Costs

A. **Individual Meter**

Economic Life: 25 years
Approximately 5% tested yearly

Estimated Costs

(i)	Labour..............................	$10.00
(ii)	Handling...........................	3.00
(iii)	Field..............................	5.00
(iv)	Total cost per meter...............	$18.00

B. **Bulk Meter**

Economic Life: 25 years
All meters tested every 6 years

Estimated Costs

(i)	Labour..............................	$24.00
(ii)	Handling...........................	3.00
(iii)	Field..............................	5.00
(iv)	Total cost per meter...............	$32.00

Source: Ontario Hydro Central Meter Services

In order to simplify computations, it was assumed that approximately five per cent of all installed individual meters are tested annually, while bulk meters are tested every six years. Ontario Hydro Central Meter Services estimates that the present cost of testing an individual meter is approximately $18.00, while the cost for a bulk meter was estimated to be approximately $32.00. This includes change-out, repair, calibration and handling.

c. Conversion and New Installation

A summary of installation costs for the two types of metering is shown in Table A4. It was estimated that the average individual meter would cost approximately $76.00, while $146.00 would be the appropriate market value of a bulk meter. Including labour and material, the cost of installing a bulk meter is about $900.60 per building. This value was also used to estimate the cost of converting an individually-metered apartment building to bulk metering.

However, the material and labour component, in the case of individual metering, varies, depending on whether the apartment

TABLE A4

Installation Costs for Meters

A. **Estimated Cost of Installing Individual Meter**

(i)	Cost of Meter*.....................	$ 76.00
(ii)	Additional Material and Labour	
	(a)...........................	24.00
	(b)...........................	101.46
(iii)	Total Cost per Meter	
	(a)...........................	$100.00
	(b)...........................	$177.46

B. **Estimated Cost of Installing Bulk Meter**

(i)	Cost of Meter**....................	$146.00
(ii)	Material and Labour	
	Current Transformers..........	180.00
	Wiring and Checking...........	124.64
	Meter Cabinet and	
	Installation..................	450.00
(iii)	Total Cost per Meter..............	$900.64

*   Based on the most common meter in use: a 120-volt 3-wire network meter, 2 element for use in 120/208-volt 3-wire service, 100 amperemeter.

** Based on a 3-phase, 4-wire transformer-related meter which measures the number of kW and kWh consumption.

building was initially bulk-metered and subsequently converted to individual metering, or initially designed to accommodate individual meters. In the latter case, it was assumed that additional material and labour costs would average approximately $24.00 per suite. The installation cost would total approximately $100.00 per suite (iia and iiia in Table A-4). For the provision of individual metering in apartment buildings originally designed for bulk metering, additional labour and material costs were increased to $101.46 per suite (iib in Table A-4), in lieu of necessary electrical modifications.

2. Benefit Considerations

A move to individual metering will yield the following two benefit streams:

1. *Energy savings,* associated with the fuel, and variable operation and maintenance expenses incurred by the generating unit that provides energy.

2. *Capacity savings,* associated with building and maintaining a system with sufficient capacity to meet all electrical demands placed on it.

System values of energy differences appear in Table B1, and are valued at mills per kWh. They are based on fuel-cost estimates prepared by the Fuels Division of Ontario Hydro, and include full escalation. Western Canadian coal and uranium prices, as well as U.S. coal prices, were used in varying proportions to arrive at final estimates. Although costs for daytime and night-time energy are available, composite costs, assuming a 16-hour day and an 8-hour night, were used in computing energy savings associated with individual metering.

TABLE B1

System Values of Energy Differences
Escalated Annual Costs in Year Shown*
Mills Per kWh

YEAR	DAY	NIGHT	COMPOSITE
1976	12.30	11.70	12.10
1977	14.10	13.10	13.77
1978	15.36	14.40	15.04
1979	15.80	14.80	15.47
1980	17.30	16.30	16.97
1981	18.87	17.53	18.42
1982	20.75	19.10	20.20
1983	22.00	20.04	21.35
1984	23.52	21.20	22.75
1985	25.16	22.44	24.25
1986	27.12	22.36	25.53
1987	29.21	22.20	26.88
1988	31.46	21.96	28.29
1989	33.86	21.63	29.79
1990	36.44	21.19	31.36
1991	37.36	19.06	31.26
1992	38.27	16.64	31.06
1993	39.17	13.89	30.75
1994	40.06	10.78	30.30
1995	40.92	7.29	29.71
1996	41.76	7.70	30.41
1997	42.57	8.12	31.08
1998	43.34	8.57	31.75
1999	44.06	9.04	32.39
2000	44.73	9.53	33.00

* System Planning, Ontario Hydro, April 29, 1976.

The values in Table B2 are for kW differences estimated to occur at the time of the system peak load in December, and are expressed in dollars per kW, discounted at twelve per cent to the starting year. In other words, a peak loss of one kW in 1980 has a value of $315.00, for the remaining period of analysis. This is the present worth in 1980 of one kW of loss continuing from 1980 to 2000, inclusive.

TABLE B2

Present Value of Peak Differences
To a Given Starting Year in Dollars per kW

STARTING YEAR	LIFE	DOLLAR VALUE
1976	25	211
1977	24	230
1978	23	256
1979	22	280
1980	21	315
1981	20	354
1982	19	385
1983	18	419
1984	17	470
1985	16	490
1986	15	524
1987	14	541
1988	13	570
1989	12	583
1990	11	593
1991	10	615
1992	9	615
1993	8	608
1994	7	608
1995	6	581
1996	5	540
1997	4	480
1999	3	400
1999	2	295
2000	1	161

Source: System Planning, Ontario Hydro,
April 29, 1976.

However, it is important to note that capacity savings, as measured in Table B2, would be realized only if residential consumption is reduced at the time of the system peak load. To determine the amount of kWs demanded at the peak, the following relationships were used: $(1) kW = (kWh/LF_c \cdot t$, and $(2) LF_c = D_R/D_S$, where

1. kW = kilowatts demanded at the time of system peak,

2. kWh = kilowatt-hours consumed in a given year,

3. LF_c - annual coincident load factor,

4. t = time period of analysis in hours (8760),

5. D_R = average residential consumption (kWh), and

6. D_S = kWh residential consumption at the time of the system peak.

Based on load analysis data,[16] it was estimated that the co-incident load factor for apartment suites ranged from 0.3 to 0.5 for the electric-heating load, and approximately 1.13 for the domestic load. However, these estimates are based on somewhat limited data sources, and for this reason, conservative estimates were used in this report: specifically, 0.4 and 1.5 were assumed to be the relevant co-incident load factors for the electric-heating and domestic load components, respectively.

3. Apartment Building Data

For the purpose of the present study, it was necessary to estimate both the number of apartment rental units, and the number of apartment structures in Ontario, up to and including the year 2000. There follows a brief discussion of the methodology employed, and the results obtained.

The estimated number of rental dwelling units, by type of structure, in Ontario in 1975, is shown in Table C1. Of the total of 950,000 dwelling units, approximately 58 per cent, or 550,000, are defined as apartment suites, located in 17,700 structures. Compared with the Statistics Canada estimate of 772,000 apartment suites for the same year, the figure in Table C1 may ap-

[16]Power Market Analysis, Ontario Hydro. The following estimates were based upon a spreading peak over a 16-hour day.

pear somewhat low.[17]
For the most part, the difference is based on definitional proce-
dure. Apartment suites are defined in this study as self-con-
tained rental dwelling units, located in separate structures origi-
nally designed as apartment buildings. Excluded from this
category are suites in condominiums, structurally converted
houses, flats, row housing, and other multiple dwellings.

TABLE C1

Estimated Number of Rental Dwelling Units
in Ontario - 1975

Type of Structure*	Dwelling Units	Number of Structures
Single-Family	200,000	200,000
Duplex	160,000	80,000
Other Multiple**	77,050	22,690
Low-Rise Apartments (6-50 Units)	225,000	15,000
High-Rise Apartments (50+ Units)	325,000	2,700
TOTAL	950,000	320,390

* Excludes boarding and rooming houses

** Includes self-contained dwelling units up to
5 units

Source: Ministry of Housing, Provincial Government.

Two types of structure are distinguished: low-rise buildings
which consist of between 6 and 50 suites, and high-rise build-
ings consisting of 50 or more suites. Although low-rise buildings
are far greater in number than high-rise buildings for the year
1975 (85 per cent are low-rise) these buildings accounted for
only 41 per cent of the total number of apartment rental suites.

On the basis of demographic projections produced by Statistics
Canada,[18]
these three basic trends are implicit in the estimate of future
housing starts and apartment completions:

1. *1976-1980.* A strong growth in single-family construction,
   because of a continuing increase in family household for-
   mation. It is expected that the average annual starts will be
   approximately 90,000 units over the period. Apartment
   completions are expected to average 20,000 units per an-
   num during the same period.

2. *1981-1990.* A moderation in total household formation is
   anticipated, resulting in a decline in the number of required
   housing starts to about 70,000 units in 1990. Apartment
   completions are expected to decline to 15,000 by 1981, fol-
   lowed by a moderate increase to approximately 18,000 by
   1990.

3. *1991-2000.* A faster rate of non-family household formation
   will be evident, because of the increasing number of per-
   sons in the age category of 15 to 25. Total required starts

will rise to approximately 85,000 units in 2000 while apart-
ment completions will average about 20,000 per annum.

Columns 1, 2, and 3 of Table C2 outline the anticipated annual
additions in the housing stock, and total and annual increase in
apartment rental units, respectively.

In order to estimate the number of additional structures through-
out the period of analysis, the composition of these buildings
was taken into consideration. Since apartment buildings range
in size from 6 to well over 200 units, separate estimates were
obtained for both low- and high-rise buildings. In 1975, low-rise
buildings averaged 15 units, while high rise buildings averaged
120 units per building. Generally speaking, new apartment
buildings tend to be larger. Apartment building starts during the
fourth quarter of 1975 indicate that, of the 115 buildings under
construction, 53 per cent of these can be classified as low-rise,
and the remaining 47 per cent as high-rise buildings.[19] Howev-
er, when the number of dwelling units are considered, the for-
mer structures account for only 11 per cent of the total 9,939
units under construction. Moreover, average structure size
ranged from 18 to 163 units for low- and high-rise buildings, re-
spectively.

Assuming the trend toward high-rise apartment buildings contin-
ues, as construction costs and increase and more land be-
comes available, it is anticipated that, by the year 2000,
approximately 96 per cent of all new apartment rental units will
be located in high-rise buildings, averaging 170 units per build-
ing. The remaining four per cent will be located in low-rise struc-
tures, containing an average of 26 dwelling units. As shown in
column 6 of Table C2, the actual number of new low-rise build-
ings will decline from 116 in 1976 to 31 by the turn of the centu-
ry. At the same time, the yearly addition of new high-rise build-
ings will increase from 109 to 113. There will be a total of
approximately 21,844 structures in Ontario by the year 2000.

4. Classification of Customers

a. Bulk Policy Option

Assuming the trend towards bulk metering continues, columns 1
through 5 of Table C3 show the annual classification of custom-
ers for the period of analysis. At present, approximately 450,000
dwelling units, located in apartment buildings throughout Ontar-
io, have been converted, or were originally designed, to accom-
modate bulk-metering. However, in estimating net conversion
costs, from bulk to individual metering, a great deal of variation
was encountered, depending on the characteristics of the build-
ing in question. Highest estimates were for apartment buildings
requiring structural work and refinishing. Since conversion costs
in these cases could run into thousands of dollars per suite, it
was assumed that this type of building would remain bulk me-
tered, and hence is excluded from the analysis.

Electrically-heated buildings were included in this category be-
cause of their structural design. On the basis of a survey of eight
municipalities, it was estimated that the number of electrically-
heated buildings would amount to approximately 400, or 80,000
dwelling units located mainly in high rises (Table C4). A further
allowance of 300 buildings, or 50,000 dwelling units, was made
in order to take into account buildings not heated by electricity
which may require substantial structural changes.

[17]Statistics Canada, *Household Facilities and Equipment,* Cat. No 64-002 (April
1975).
[18]Statistics Canada, *Technical Report on Population Projections for Canada and
the Provinces,* Cat. No 91-516, (July 1975). For all intents and purposes, the
estimates presented below may be interpreted as being on the conservative side.
[19]Statistics Canada, *Housing Starts and Completions,* Cat. No 64-002 (May 1976).

TABLE C2: ESTIMATED HOUSING STARTS IN ONTARIO – 1976-2000

	(1)	(2)	(3)	(4)		(5)		(6)		(7)
	Annual Increase [1]	Apartment	Annual	Distribution of Units		Units per Structure		Additional Bldgs		Total
Year	in Housing Starts '000	Rental Units '000	Increase '000	Low Rise	High Rise	Low Rise	High Rise	Low Rise	High Rise	Year End Stock
1976	90	570	20	2,200	17,800	19	163	116	109	17,925
1977	90	590	20	2,200	17,800	19	163	116	109	18,150
1978	90	610	20	2,200	17,800	19	163	116	109	18,375
1979	90	630	20	2,000	18,000	20	164	100	110	18,585
1980	90	650	20	2,000	18,000	20	164	100	110	18,795
1981	85	665	15	1,500	13,500	20	164	75	82	18,952
1982	85	680	15	1,350	13,650	21	165	64	83	19,099
1983	80	695	15	1,350	13,650	21	165	64	83	19,246
1984	80	710	15	1,350	13,650	21	165	64	83	19,393
1985	75	725	15	1,350	13,800	22	166	55	83	19,531
1986	70	743	18	1,440	16,560	22	166	65	100	19,696
1987	70	761	18	1,440	16,560	22	166	65	100	19,861
1988	70	779	18	1,260	16,740	23	167	55	100	20,016
1989	70	797	18	1,260	16,740	23	167	55	100	20,171
1990	70	815	18	1,260	16,740	23	167	55	100	20,326
1991	75	835	20	1,200	18,800	24	168	50	112	20,488
1992	75	855	20	1,200	18,800	24	168	50	112	20,650
1993	75	875	20	1,200	18,800	24	168	50	112	20,812
1994	80	895	20	1,000	19,000	25	169	40	112	20,964
1995	80	915	20	1,000	19,000	25	169	40	112	21,116
1996	80	935	20	1,000	19,000	25	169	40	112	21,268
1997	85	955	20	800	19,200	26	170	31	113	21,412
1998	85	975	20	800	19,200	26	170	31	113	21,556
1999	85	995	20	800	19,200	26	170	31	113	21,700
2000	85	1,015	20	800	19,200	26	170	31	113	21,844

[1] Estimates obtained from The Ontario Ministry of Housing.

[2] Based on a decrease of one percentage point every three years in the number of dwelling units in low rise buildings.

[3] Average sturcture size increases by one unit every three years.

TABLE C3

CLASSIFICATION OF CUSTOMERS

1976-2000

	(A) BULK OPTION					(B) INDIVIDUAL OPTION					
YEAR	(1) STOCK	(2) NEW	(3) CONVERSIONS	(4) TOTAL	(5) INDIVIDUAL	(6) STOCK	(7) NEW	(8) CONVERSION	(9) TOTAL	(10) BULK	(11) BUILDINGS
1976	12,000	225	2,500	14,725	50,000	100	20	60	180	260	9.65
1977	14,725	225	2,500	17,450	***	180	20	60	260	200	7.30
1978	17,450	225	***	17,675		260	20	60	340	140	4.95
1979	17,675	210		17,885		340	20	60	420	80	2.60
1980	17,885	210		18,095		420	20	80	520	***	***
1981	18,095	157		18,252		520	15	***	535		
1982	18,252	147		18,399		535	15		550		
1983	18,399	147		18,546		550	15		565		
1984	18,546	147		18,693		565	15		580		
1985	18,693	138		18,831		580	15		595		
1986	18,831	165		18,996		595	18		613		
1987	18,996	165		19,161		613	18		631		
1988	19,161	155		19,316		631	18		649		
1989	19,316	155		19,471		649	18		667		
1990	19,471	155		19,626		667	18		685		
1991	19,626	162		19,788		685	20		705		
1992	19,788	162		19,950		705	20		725		
1993	19,950	162		20,112		725	20		745		
1994	20,112	152		20,264		745	20		765		
1995	20,264	152		20,416		765	20		785		
1996	20,416	152		20,568		785	20		805		
1997	20,568	144		20,712		805	20		825		
1998	20,712	144		20,856		825	20		845		
1999	20,856	144		21,000		845	20		865		
2000	21,000	144		21,144		865	20		885		

Electrically-Heated Apartment Buildings
In Selected Municipalities - 1976

Municipality	Dwelling Units	Proportion of Total	Number of Buildings
East York*	4,793	.23	14
Hamilton	2,296	.33	18
London	1,531	.14	26
Mississauga	5,000	.27	66
North York*	4,323	.08	41
Ottawa	6,600	.19	55
Scarborough	1,669	.04	14
Toronto	19,000	.30	100
TOTAL	45,212	.18	334

* Adjusted for 1976

Adjusting the initial stock of apartment buildings for the above-mentioned factors results in a total of 17,000 buildings, 12,000 of which are bulk-metered (column 1). It was assumed that the remaining 5,000 individually metered buildings would be converted to bulk metering within two years. These are shown in column 3, while the number of remaining dwelling units serviced with individual meters is shown in column 5. By the turn of the century, approximately 21,144 apartment buildings would be serviced with bulk meters.

b. Individual Policy Option

The classification of customers under this policy option is shown in columns 6 through 11 of Table C3. The initial stock of 100,-000 dwelling units shown in column 6 refers to those buildings that would likely have been converted under the bulk policy option. For this reason, they must be included under the individual policy option as well.

Column 7 shows the annual addition of new apartment dwelling units, corresponding to the number of additional apartment buildings shown in column 2 of the same table.

The classification of customers during the conversion period is shown in columns 8, 10, and 11. For the purpose of this report, it was assumed that conversion of 320,000 dwelling units would take place over a period of approximately five years, beginning in 1976. Although arbitrarily chosen, it seems that conversion could be completed well within the allotted period. For example, in the first year, approximately 60,000 dwelling units located in 2,350 buildings would have to be converted in order to have all dwelling units individually metered by the end of 1980. Barring work stoppages and other working delays, this is equivalent to converting about 10 apartment buildings, containing an average of 27 dwelling units, each working day,[20] for the next five years. Considering that over 400 municipalities would be involved in the process, it seems reasonable to assume that the task could be accomplished within five years.

Column 8 of Table C3 shows the actual number of yearly conversions of dwelling units, while columns 10 and 11 show the

dwelling units and actual buildings, respectively, that have yet to be converted. In any given year, it is assumed that the total number of dwelling units converted is evenly distributed throughout the year. This would mean that a converted dwelling unit is serviced with an individual meter for only six months of the year during which the conversion takes place. This allows less-complicated computations in estimating costs and benefits corresponding to new additions to the annual apartment stock (columns 2 and 7 of Table C3).

In order to compute annual capacity savings associated with individual metering, it was necessary to distinguish between electrically- and non-electrically-heated dwelling units, since additional kWh consumption would be higher in the former than in the latter type of dwelling unit. Although a recent trend towards electric space-heating is evident in new multiple dwelling units in Ontario, it was assumed that approximately 35 per cent of new dwelling units would be electrically heated from 1976 to 2000, inclusive.[21]

Tables C5 and C6 show the annual number of electrically and non-electrically heated apartment dwelling-units for the period of analysis. In addition, column 3 in both tables gives the number of occupied dwellings, used as the basis for cost and saving computations. Occupied dwellings were determined by assuming a vacancy rate of two per cent for all years, except the period 1981 to 1985, for which a 2.5-per-cent rate was assumed.

TABLE C5

Electrically-Heated Apartment Dwelling Units
In Ontario - 1976-2000

'000

Year	(1) New Suites	(2) Total	(3) Occupied Dwellings New	(3) Occupied Dwellings Total
1976	7.0	7.0	6.86	6.86
1977	7.0	14.0	6.86	13.72
1978	7.0	21.0	6.86	20.58
1979	7.0	28.0	6.86	27.44
1980	7.0	35.0	6.86	34.39
1981	5.3	40.3	5.17	39.29
1982	5.3	45.6	5.17	44.46
1983	5.3	50.9	5.17	49.63
1984	5.3	56.2	5.17	54.80
1985	5.3	61.5	5.17	59.96
1986	6.3	67.8	6.17	66.44
1987	6.3	74.1	6.17	72.62
1988	6.3	80.4	6.17	78.79
1989	6.3	86.7	6.17	84.97
1990	6.3	93.0	6.17	91.14
1991	7.0	100.0	6.86	98.00
1992	7.0	107.0	6.86	104.86
1993	7.0	114.0	6.86	111.72
1994	7.0	121.0	6.86	118.58
1995	7.0	128.0	6.86	125.44
1996	7.0	135.0	6.86	132.30
1997	7.0	142.0	6.86	139.162
1998	7.0	149.0	6.86	146.02
1999	7.0	156.0	6.86	152.88
2000	7.0	163.0	6.86	159.74

[20]Assuming 250 working days in a year.
[21]Power Market Analysis, Ontario Hydro.

TABLE C6

Non-Electrically-Heated Apartment Dwelling Units
In Ontario - 1976-2000
'000

| Year | (1) New Suites | (2) Total | (3) Occupied Dwellings | |
			New	Total
1976	13.0	13.0	12.74	12.74
1977	13.0	26.0	12.74	25.48
1978	13.0	39.0	12.74	38.22
1979	13.0	52.0	12.74	50.96
1980	13.0	65.0	12.74	63.74
1981	9.7	74.7	9.46	72.83
1982	9.7	84.4	9.46	82.29
1983	9.7	94.1	9.46	91.75
1984	9.7	103.8	9.46	101.21
1985	9.7	113.5	9.46	110.67
1986	11.7	125.2	11.47	122.70
1987	11.7	136.9	11.47	134.17
1988	11.7	148.6	11.47	145.64
1989	11.7	160.3	11.47	157.11
1990	11.7	172.0	11.47	168.58
1991	13.0	185.0	12.74	181.30
1992	13.0	198.0	12.74	194.04
1993	13.0	211.0	12.74	206.78
1994	13.0	224.0	12.74	219.52
1995	13.0	237.0	12.74	232.26
1996	13.0	250.0	12.74	245.00
1997	13.0	263.0	12.74	257.74
1998	13.0	276.0	12.74	270.48
1999	13.0	289.0	12.74	283.22
2000	13.0	302.0	12.74	295.96

APPENDIX VI: Residential Time-of-Day Metering

Two-rate metering of residential load makes it possible to apply rates based on marginal cost, which in turn provide an incentive for reducing consumption. This system of metering time-of-day pricing to residential as well as large industrial customers, resulting in lower capital and energy requirements.

A comparison of the resource costs and benefits of single-rate, optional two-rate, and full-scale two-rate metering in Ontario, over the period from 1978 to 2000 inclusive has been made (see accompanying diagram). Depending on estimated sensitivity of customers to the price of electricity, the net saving through the use of optional two-rate metering may be between 0.5 and 122 million 1978 dollars. Full implementation of two-rate metering may increase costs by as much as 35 million 1978 dollars, or result in a net saving of up to 638 million 1978 dollars.

The benefits of time-of-day metering are highly dependent on the customers' degree of price sensitivity, or for electricity. No peak, off peak cross price elasticities were available at the time this analysis was undertaken.

A. INTRODUCTION

The structure of rates charged for electricity has a definite effect on how much energy is used for different purposes.

The rates should reflect variations in production costs caused by seasonal and daily load cycles. This will prevent the use of expensive peak energy for low-priority purposes. Seasonal rate variations can be handled by using different rates for certain months of the year. Daily variations in rates require some form of time-of-day metering.

Time-of-day metering records the load for different parts of the day separately, permitting the application of several different rates. Large industrial and commercial customers already have metering equipment which records sufficient information to allow Ontario Hydro to implement time-of-day rates. The cost of providing suitable metering equipment for those larger industrial and commercial customers who do not have this equipment is small in relation to the total cost of supplying energy to them.

Residential customers, on the other hand, do not have meters suitable for the application of time-of-day rates, and it is not immediately apparent whether installing such equipment would be worthwhile. This appendix discusses the practicalities of residential two-rate metering, which is a simple form of time-of-day metering. A two-rate meter records kilowatt-hour consumption during peak and off-peak periods on two separate registers, Alternatively, the total consumption is recorded on one register and the peak consumption on the other. A three-rate meter would similarly record different portions of the load on three different registers. The cost of such meters, of maintaining and reading them, and of billing customers would be considerably greater than that for two-rate metering. Since Ontario Hydro's daily load curves show one broad peak, there would be little to be gained from the additional expense and complexity of three-rate metering.

It should be noted that, in this study, the purpose of implementing two-rate metering has been assumed to be to track time variations in costs. Thus, the calculations have been made using rate differentials approximating those expected from marginal-cost calculations.

If the purpose of two-rate metering were to improve load shape, a larger rate differential could produce a suitable customer response. However, such an incentive would be artifical, and although it might induce more efficient loading of Ontario Hydro

plant, it would not represent the least-cost solution for society: that is, there would be a net cost to society because of the larger rate differential.

B. PRESENT USE OF TWO-RATE METERING

No two-rate metering occurs in Canada, and only a small amount in the United States. Since about 1971, two-rate time-of-day metering has been widely available throughout England and Wales. A restricted-hour rate for water heaters is alo available in some areas of the United Kingdom. Time-of-day metering is widespread in Switzerland and the Netherlands, and in France large savings are estimated from its use. West Germany has made a significant improvement in load factor by the use of load control and time-of-day metering. In Belgium, time-of-day metering is optional.

C. AVAILABLE METHODS OF TWO-RATE METERING

Two methods of two-rate metering are the following:

1. One Meter with Internal Timer

Meters can be readily obtained with self-contained timers which engage one of two registers at a pre-set time.

Sangamo received approval in 1966 from the Standards Branch of the Department of Trade and Commerce of Canada, now the Department of Consumer and Corporate Affairs, for a single-phase watt-hour meter with a two-rate register and a self-contained timer. They manufactured approximately 100 meters in 1966, but have not made any since.

General Electric manufactures a single-phase watt-hour meter, with a two-rate register and a self-contained timer. This meter also contains a switch that can be used to energize an external load, while one register is engaged, and to cut off the power when the other register is engaged. This could provide customer indication, or perhaps control an appliance, ensuring that it is only used during the low-rate period.

2. Two Meters and External Switch

Two single-rate meters can be connected so that one operates during the off-peak period, and both operate during the peak period.

a. Time-Operated Switch

General Electric manufactures a time-operated switch to turn the second meter on and off. A spring-driven carry-over is available to maintain timer accuracy during outages from 30 to 36 hours. However, daylight-saving time still makes necessary two resets a year. These might be avoided if the summer peak/off-peak periods were modified, but the winter periods were measured strictly.

b. Remotely Operated Switch

A remotely operated switch provides flexibility, and freedom from disturbance by outages. Pilot-wire and ripple-control systems have been used for many years to switch water heater load; but both require additional equipment, which adds to the cost. If a remote-control system were established for other purposes (perhaps network control), then the additional cost would only be for the receiver.

D. POSSIBLE METHODS OF TWO-RATE METERING

Several conceivable methods of two-rate metering which might be developed to the point of practical application in the future are the following:

COST COMPONENTS

OPTION

CONVERSION TO TWO-RATE METERING | OPTIONAL TWO-RATE METERING | CONTINUATION WITH SINGLE-RATE METERING

NEW TWO-RATE METERS | NEW SINGLE-RATE METERS

BASIC COSTS

READING & BILLING TWO-RATE METERS | READING & BILLING SINGLE-RATE METERS

CHECKING TWO-RATE METERS | CHECKING SINGLE-RATE METERS

RECALIBRATING TWO-RATE METERS | RECALIBRATING SINGLE-RATE METERS

EXTRA COSTS

REPROGRAMMING BILLING COMPUTER

INSTALLATION LESS SALVAGE

RESETTING TWO-RATE TIMERS

STORAGE HEATERS

SAVINGS

ENERGY SAVING DUE TO LOAD SHIFT

ENERGY SAVING DUE TO CONSERVATION

CAPITAL SAVING DUE TO PEAK REDUCTION

NET COST

CONVERSION TO TWO-RATE METERING | OPTIONAL TWO-RATE METERING | CONTINUATION WITH SINGLE-RATE METERING

1. Measuring Cost Rather than Quantity

A slightly unorthodox method of two-rate metering is to allow a single-rate meter to run normally for the high rate period, and slow it down during the low-rate period by switching a small auto-transformer into the potential circuit to reduce the voltage. This is equivalent to changing the meter multiplier. It has the advantage that the switch-over is made electrically, not mechanically, and therefore should be considerably more reliable than the mechanism commonly used to engage and disengage registers in a typical two-rate meter.

It is unorthodox in that the measured quantity is proportional to utility cost rather than a precise measure of the quantity of electricity consumed. In this sense, it is similar to a non-linear meter recently proposed.[22]

Such meters presently contravene the regulations of the Department of Consumer and Corporate Affairs.

If approval were obtained for such a two-rate meter, it could be controlled by a timer or by several remote methods. Remote control is more flexible but requires additional equipment.

2. One Meter and External Switch

A standard two-rate meter could be obtained with a solenoid in place of the timer-mechanism that engages and disengages the registers. This would permit the use of any of several remote control methods, all of which provide greater flexibility than a timer, at a slightly higher cost.

3. Solar Control

A photo-cell could be used to switch registers at sunrise and sunset, if such broadly-defined periods were suitable. In 1966 a patent[23] was issued covering a clock-driven switch with a solar reset. It would be difficult to make any device employing solar control tamper-proof.

4. Timer with Remote Resetting

Several methods of remote control could be applied to reset the timer controlling a two-rate meter. However, it is likely that a remote control system the timer could completely eliminate and the remote control could engage and disengage the registers directly.

5. Solid-State Meter

In the distant future, low-cost, integrated circuits may be developed which can combine metering, storage in multiple registers, and read-out functions, on one or two chips. Register selection and read-out might be controlled by a remote computer via cable television, or telephone lines, or powerline-carrier or ripple signals.

E. RESPONSE TO TWO-RATE METERING

Two-rate metering performs a useful function because it allows the customer to face the cost consequences of using electricity in different time periods. The customer may then decide to alter his pattern of consumption in response to the difference in rates. The response to peak/off-peak pricing is made up of the following components:

1. Elastic Load Shift

Following the establishment of different rates for peak and off-peak hours, some shift may result. Some of this load shift will help to reduce the system peak, and some will not. For simplicity of analysis, the two shift components have been assumed to be proportional.

The peak and off-peak loads may independently respond to the change of price during their respective periods. In addition, there may be some load shifted from peak to off-peak time. The magnitude of these shifts can be determined using elasticity factors.

At present, elasticities are not well defined, but NERA[24] suggests that residential customers may have aggregate elasticities of -0.5. It must be noted that these elasticities apply for small changes in a single rate. Very little work has been done on elasticities of demand which depend on the time of day. Elasticities describing peak-period response may be similar to those for single rates. For off-peak response, it has been assumed that customers' energy requirements are less flexible during the night than during the day, and therefore smaller elasticity factors have been used for off-peak-period than for peak-period consumption.

Peak/off-peak cross-price elasticity, describing the response by load shift from peak to off-peak time, is more elusive. Off-peak electricity may be assumed to be a substitute for peak electricity for some uses, but it may also complement peak electricity in other cases. For the purpose of this study, it has been assumed that the substitutive uses outweigh the complementary uses, and a small net positive elasticity has therefore been assumed.

Some variations around the following assumed elasticities have been made: Peak, -0.5; Off-Peak, -0.3; Cross, 0.1.[25]

2. Electric-Heating Load Shift

It is assumed that the load for conventional electric heating will respond to rate changes in two ways:

1. A short-term response is anticipated in the form of reduced peak consumption and increased off-peak consumption, that is, setting the thermostat lower in the daytime and not turning it down so much at night. In Ontario this type of response is not expected to be large because of the cold climate, and the following elasticities have been used as a result: Peak, -0.2; Off-Peak, -0.2.

   b. A long-term response in the form of more homes being heated by electricity is expected, because of the high proportion of their off-peak consumption resulting in a lower total bill with two-rate metering, than with single rate metering. A NERA report[26] indicates that long-term elasticities for electric heating may be from -2 to -3. This could result in a significant increase in the number of electrically-heated homes, unless the total increases in the price of electricity, relative to that of other fuels offsets the expected saving.

However, a quantitative analysis of customer response requires knowledge of cross-price elasticities and projected fuel prices. Because of the difficulty in accurately determining these factors, the effect of alternate fuel substitution has not been considered.

3. Storage Heating

The anticipated difference in rates alone will not be sufficient to induce a customer to install storage heating without social pressures, external economic constraints, and possible regulation by

[22]"New Rates/Metering Approach Proposed", *Electrical World*, 1 April 1976, p. 48.
[23]C.J. Armstrong, Patent on Light Responsive Off-Peak Utility Switch, #3,244,888, 5 April 1976
[24]*Summary Critique of Residential, Commercial, and Industrial Demand*, Exhibit LAG-2, Testimony of Louis A. Guth (Vice-President NERA) before PSC, New York, June 1975
[25]Peak/off-peak cross price elasticity.
[26]*Summary Critique*

authorities. A customer might install a storage heater if it cost less than the amount he would expect to save as a result of the difference between the rates for peak and off-peak power.

The annual saving to customers is estimated on the basis of the peak period portion of an average yearly electric heating load multiplied by the rate differential.

F. BENEFITS OF TWO-RATE METERING

If two-rate metering causes a load shift from peak to off-peak time, a saving will be realized in the amount of plant required to meet the peak load, and in the type of fuel used to supply that load.

1. Capital Saving

The saving as a result of the above peak reduction is evaluated using a marginal cost of capacity of $802.10 per kilowatt (see Annex D).

2. Saving in the Cost of Energy

A saving will be realized as a result of this shift due to the lower cost of off-peak energy. This saving is equal to the cost of peak power multiplied by the decrease in peak load, less the cost of off-peak power multiplied by the increase in off-peak load.

3. Energy Conservation

Some uses of peak electricity may be dropped entirely, rather than transferred to off-peak times. This will result in a net saving of energy. This is included in the savings in the cost of energy, as calculated above. The total energy saving over the study period has been determined in kilowatt-hours. Environmental savings as a result of this lower-production have not been estimated.

4. Limitations

The saving as a result of load shift is limited by the following two factors:

a. Winter Night Valley

Ontario Hydro's peak load occurs during the day in December or January each winter. Load transfer from day to night will be beneficial until the night valley begins to fill. The present winter night valley is approximately 35 percent of peak. The maximum, beneficial, load shift is somewhat less than this because of present plant mix, and much less is anticipated.

b. Summer Valley

The summer valley is used for planned maintenance and too large a winter peak reduction might reduce the capacity for maintenance. With the anticipated rate differential a large peak reduction is not expected.

G. COSTS OF TWO-RATE METERING

1. Public Acceptance

Depending on public acceptance of storage heating, little or no sales effort may be required to obtain its optimum use. It is possible that the present organization could handle the extra work without additional expenditure. A market survey would be required to estimate the sales effort required. For this reason, this cost has not been considered in this economic comparison.

2. Meters

Ontario Hydro is using two types of single-rate meters now. It is estimated that in 1978 the A-base meter will cost $39.98, and the S-base meter will cost $29.65. Approximately 18,000 A-base meters will be purchased each year for the first six years to replace 15 Amp meters. All new customers will receive S-base meters.

It is estimated that two-rate meters, with an external clock with spring-driven carryover and weekend over-ride, would cost approximately $160 each in quantity.

3. Resetting Timers

Any significant outage, or a series of momentary outages could cause the timers in two-rate meters to become inaccurate. It has been estimated that resetting a timer might cost approximately twice as much as reading the meter. In 1974, it cost Ontario Hydro 73 cents to read each meter (Annex C). Therefore, the cost of resetting a timer of $2.00 has been assumed to be $2.00. It is also assumed that resets for daylight saving time would be eliminated by optimizing the peak and off-peak periods for winter. Allowing for one outage every ten years that cannot be handled by carry-over, brings the number of resets per year to 0.1 per customer.

4. Installation and Salvage

Some cost would be involved in replacing a single-rate meter with a two-rate device. It is expected that it might take about 30 minutes and, therefore, cost approximately $20. The salvage-value of the removed meter is assumed to be zero, except in the case of optional two-rate metering where it is assumed to equal one-half the price of a new single-rate meter.

5. Testing Meters

The reliability of conventional single-rate meters has been well established by a extensive use over a number of years. This permits a statistical sampling procedure to be used to reduce the amount of testing required. Meters are installed in lots of 10,000. Beginning eight years after installation, samples of 200 meters are tested every two years. When an unsatisfactory sample is found, the entire lot of 10,000 meters is recalibrated and re-installed.

Two-rate meters have not had the widespread use in North America that single-rate meters have had, and without a large body of statistical records, a much more stringent testing procedure will be necessary, at least initially. Once sufficient statistical data obtained, the testing can again be done on a sample basis. Nevertheless, it is quite possible that even then a shorter interval between tests may be necessary, because two-rate meters are more complicated. Regardless of the length of the interval, the testing will definitely require more time per meter, because of the clock and the additional register. Thus the calibration of two-rate meters will involve more personnel, and will cost considerably more per meter.

Ontario Hydro's Central Meter Services estimates that the present cost of testing a single-rate meter is approximately $18. This includes change-out, repair, calibration and handling. It is expected that testing a two-rate meter would cost approximately $25.

6. Reading and Billing

Reading and billing costs for single-rate meters in 1974 amounted to approximately $9.34 per customer. (see Annex C).

The cost components which will be increased by a change to two-rate metering are the following:

a. Meter Reading

On the average a meter reader spends approximately 10 per cent of his time actually taking a reading. Assuming that reading a two-rate meter takes twice as long as reading a single-rate meter, a cost of 110 per cent greater than that for reading a single-rate meter would result.

b. Area Clerical

Each meter reading is entered in the billing computer from a remote terminal, along with the appropriate customer account number. Assuming a 50 per cent increase in time to enter two meter readings per customer, would result in a 50 per cent increase in cost.

c. Computing

The computing cost includes maintenance costs and rental costs for terminals and lines which can be assumed to be the same for single and two-rate metering. The data validation and running costs can be assumed to increase by 50 per cent for a change to two-rate metering, because a certain amount of additional calculation must be made after each customer account is assessed in the memory.

d. Re-adjustments

Manual calculation of bills will also probably take 50 per cent longer for two-rate metering.

7. Computer Programming

The billing computer would require extensive reprogramming to store an extra reading in the memory for each customer, and to calculate each bill with two readings. The procedures for collecting meter data would also require modification to handle two-rate meters. Stocking procedures would have to be changed to handle both single and two-rate meters. A cost of $400,000 has been included in the first year of the study to allow for these costs.

8. Statistics

Analysis of load data will be somewhat more complicated for two load periods. However, since statistical analysis is neither directly associated with, nor absolutely necessary for, implementation of two-rate metering, any increase in this cost has not been taken into consideration. Present staff may be sufficient for a small amount of statistical analysis to assist in optimizing two-rate metering.

9. Storage Heating

The storage heater is purchased by the customer, out of the saving he makes by using low-cost off-peak power. It reduces his benefits and, thus, is a net cost to society.

A Research Division position paper[27] and a Rate Research Department heat storage report[28] describe briefly several storage heaters and a discussion with the manufacturer of the prototypes. Based on these descriptions, it has been estimated that a production storage heater, suitable for residential use, would cost approximately $1500 to $2000, depending on the number of units manufactured per year.

H. RESOURCE COST-BENEFIT MODEL

A model containing the parameters mentioned above (computer program Annex E) has been used to make an economic comparison between single and two-rate metering over the period from 1978 to 2000 inclusive. For the purpose of this study, two-rate meters and clock controlled switches are assumed to provide the simplest and most straight-forward means of achieving time-of-day metering. However, a remotely controlled meter might be used if time-of-day metering were adopted on a sufficiently large scale. Such a scheme would be much more flexible than a simple clock-controlled system, and would not be disturbed by outages. It might also provide other operating benefits such as remote load switching.

Two basic types of comparison have been made. The cost of total conversion to two-rate meters in ten years has been calculated. However, almost the same benefits can be achieved by providing the two-rate meters only to those customers who can take advantage of off-peak rates. This avoids the cost of providing two-rate meters to customers who will not or cannot respond. Therefore, the cost of an optional two-rate metering proposal has also been calculated.

1. Limitations

a. Rate Simulation

Marginal rates probably will not follow exactly from the assumption on the basis of which peak and off-peak rates were determined in this study. It is here assumed that the peak and off-peak rates would be set in such a manner that an average customer's total bill in a compulsory two-rate scheme, would remain the same as with single-rate metering, if he did not alter his consumption pattern. Nevertheless, it is assumed that the approximate rates are adequate for the purpose of comparing single and two-rate metering. Therefore, any customer response results from two-rate metering.

b. Effect of Response

The effect of customer response in a given year is not reflected in a decreased rate differential for that year or for subsequent years, so the incentive for change remains at a maximum level. Because of this, the actual response to two-rate metering will be less than the study indicates. However, with the expected rate differential and elasticities, the customer response would be so small that rate re-adjustments would not be significant.

Those customers whose consumption of electricity includes more than the average amount of off-peak power, could make a saving through the use of a two-rate meter, causing the weighting of the remaining single-rate customers to be shifted slightly toward peak time. This should result in a slightly higher single rate, which would encourage even more use of optional two-rate metering.

The effect of this slight additional incentive has not been considered, an omission which tends to reduce the response to optional two-rate metering. However, the excess incentive due to constant rate differential is expected to outweigh this reduction, and it would be counteracted to a large extent by the higher two-rate meter customer charge.

2. Results

The costs of single-rate, optional two-rate, and compulsory two-rate metering were determined using different rate differentials and elasticities.

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[27] Research Division position paper on point-of-use Energy, in Storage.
[28] Residential Electric Heating Load Characteristics, Report #RR-61-19

OPTION

CONVERSION TO TWO-RATE METERING	OPTIONAL TWO-RATE METERING	CONTINUATION WITH SINGLE-RATE METERING

BASIC COSTS

NEW TWO-RATE METERS		NEW SINGLE-RATE METERS		
316.6	33.6	0.0	14.3	19.9

READING & BILLING TWO-RATE METERS		READING & BILLING SINGLE-RATE METERS		
539.2	57.8	127.5	541.9	591.7

CHECKING TWO-RATE METERS		CHECKING SINGLE-RATE METERS		
4.3	0.5	0.0	4.3	4.7

RECALIBRATING TWO-RATE METERS		RECALIBRATING SINGLE-RATE METERS		
0.4	1.3	0.0	13.5	14.4

EXTRA COSTS

REPROGRAMMING BILLING COMPUTER	
0.4	0.4

INSTALLATION LESS SALVAGE	
37.6	0.4

RESETTING TWO-RATE TIMERS	
7.1	0.8

STORAGE HEATERS	
1.7	2.2

SAVINGS

ENERGY SAVING DUE TO LOAD SHIFT	
33.9	3.8

ENERGY SAVING DUE TO CONSERVATION	
54.8	6.1

CAPITAL SAVING DUE TO PEAK REDUCTION	
453.3	98.8

NET COST

CONVERSION TO TWO-RATE METERING	OPTIONAL TWO-RATE METERING	CONTINUATION WITH SINGLE-RATE METERING
501.2	562.3	630.7

Some recent studies have expressed concern for future genera-
tions as resources become more scarce and, barring unfore-
seen technological breakthroughs, the cost of living increases in
real terms. One dollar saved in the future may be more valuable
in real terms than we would be led to believe by the application
of conventional present value factors. To allow for this, this
study has used a five per cent annual discount factor in eco-
nomic comparisons, rather than the typical interest rate of 12%.
This rate has been used as an approximation of the social rate
of discount, and has the effect of weighting the comparison to-
wards the later years.

The costs of single-rate, optional, and compulsory two-rate me-
tering were calculated with a five per cent discount factor. As
expected, the ratios of benefit to cost turn out to be greater than
those that would result from using the conventional discount
factor, because the benefits of time-of-day metering are
weighted toward the later years.

A summary of the results follows, and details can be found in
Annex A.

3. Sensitivity Analysis

A sensitivity analysis was made to determine which parameters
are particularly critical. The percentage change in total cost for
a one per cent change in each parameter is listed in Annex B.
The sensitivity factors shown were calculated using a ten per
cent change in each parameter.

4. Critical Assumptions

The critical assumptions as determined in the sensitivity analysis
are those which show a large difference between the single-rate
sensitivity factor and either of the two-rate sensitivity factors.
None of the parameters show large differences as far as op-
tional two-rate metering is concerned. Those parameters of
compulsory two-rate metering which fall into this category have
sensitivity factors of less than unity. Thus, none is very critical.
However, even these moderately critical assumptions can be
significant if there is sufficient uncertainty as to the values to be
assigned to them.

a. Reading and Billing Costs

The single and two-rate meter reading and billing costs are simi-
larly derived, and a change in one would necessarily imply a
similar change in the other, tending to cancel the net change in
cost difference.

b. Elasticity Factors

Since the factors used for peak and off-peak elasticity and cross
elasticity are not well defined, a number of additional calcula-
tions have been made using a range of possible values.

c. Peak/Off-Peak Rate Differential

The rate differential, which provides the incentive for requests
for optional two-rate meters and for installation of storage heat-
ers, obviously has a strong influence on the costs of two-rate
metering. In the case under discussion, where the anticipated
rate differential is low, and the cost of storage heaters is high, lit-
tle or no storage heating would be installed. If the rate differen-
tial were higher, or some form of low-cost storage heating were
available, then small variations in the rate differential would
cause large changes in the costs.

In that case, such adjustment of the rate differential as might be
necessary from time to time would have to be done gradually.
As it stands, barring some technical breakthrough in storage
heaters, or some other off-peak load, the rate differential is only
moderately critical. Since the differential between peak and off-
peak rates has not yet been precisely detrmined, several possi-
ble values have been used in the calculations.

5. Optimum Load Shift

Two factors which may alter the optimum amount of residential
load shift are industrial load shift and combined solar and elec-
trical storage heating.

Industrial Load Shift

It is expected that industry will respond to peak and off-peak
pricing to some extent. However, the strength of the response is
not easy to predict. If a large industrial load shift occurs, little or
no night valley may be left for residential load shift.

Combined Solar and Storage Heating

A recent proposal would combine solar storage heating with
backup electric storage heating. With the present trend in fuel
costs, such a scheme could conceivably become sufficiently at-
tractive to achieve wide acceptance. To take advantage of the
lower cost of off-peak power, customers with this type of heat-
ing would likely choose two-rate metering, even if the rate differ-
ential were small.

6. Conservation of Energy

The saving in terms of marginal costs due to energy conserva-
tion has been calculated, and is included as one of the benefits
of time-of-day metering. However, some of the estimated energy
conservation may result from substitution of other fuels for elec-
tricity, and therefore would not represent a net saving to
society.[29] This would tend to reduce the benefits of time-of-day
metering. Nevertheless, since the saving due to energy conserv-
ation accounts for less than 15 per cent of the total saving, the
results of the study would not be significantly altered even if half
of the saving due to conservation were the result of substituting
of other fuels.

No attempt has been made to estimate the additional environ-
mental saving which might result from non-production. An at-
tempt to estimate the additional value of conservation to future
generations can be made by comparing the saving due to con-
servation in run 7 (summary of study results) which uses a five
per cent discount factor to emphasize future costs and benefits
with the saving due to conservation as calculated in run 4. With-
out suggesting that five per cent provides an accurate assess-
ment of the future value of energy, run 7 does indicate approxi-
mately three times more saving due to conservation than run 4.
Consideration of these two factors tends to increase the relative
benefit of compulsory two-rate metering over the optional sys-
tem.

I. CONCLUSIONS

The following conclusions have been made, keeping in mind the
stated assumptions and limitations.

1. Optional Two-Rate Metering

Optional use of two-rate metering, where the customer pays for
the additional costs of the meter by paying a slightly higher cus-
tomer charge, avoids the high cost of providing two-rate meter-
ing for customers who will not or cannot take advantage of off-

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[29]The elasticities used attempt to minimize this by excluding interfuel elasticity

SUMMARY OF STUDY RESULTS
(Details in Annex A)

Run	Differential (cents/kWh)	Elasticities Peak	Off-Peak	Cross*	Conservation (GWh)**	Net Cost	Additional Cost (millions of 1978 dollars)	Total Saving (millions of 1978 dollars)	Net Saving (millions of 1978 dollars)	Benefit/Cost Ratio
Single-Rate Metering 1-6						631				
7****						1353				
Optional Two-Rate Metering 1	0.7	-0.3	-0.2	0.1	0.008	630	1.31	1.83	.52	1.4
2	0.7	-0.5	-0.3	0.1	0.014	630	1.31	2.25	.94	1.7
3	0.7	-0.5	-0.3	0.3	0.018	629	1.31	2.71	1.40	2.1
4	1.0	-0.3	-0.2	0.1	0.49	562	40.3	109	68.7	2.7
5	1.0	-0.5	-0.3	0.1	0.85	537	40.3	134	93.7	3.3
6	1.0	-0.5	-0.3	0.3	1.09	508	40.3	162	121.7	4.0
7*****	1.0	-0.3	-0.2	0.1	0.49	1098	37.6	293	255.4	7.8
Full Scale Two-Rate Metering 1	0.7	-0.3	-0.2	0.1	3.16	666	411	376	-35	0.9
2	0.7	-0.5	-0.3	0.1	5.55	497	411	545	134	1.3
3	0.7	-0.5	-0.3	0.3	7.07	310	411	732	321	1.8
4	1.0	-0.3	-0.2	0.1	4.51	501	413	542	129	1.3
5	1.0	-0.5	-0.3	0.1	7.93	260	413	784	371	1.9
6	1.0	-0.5	-0.3	0.3	10.11	-7***	412	1050	638	2.5
7*****	1.0	-0.3	-0.2	0.1	4.5	211	368	1510	1142	4.1

* Peak/Off-Peak Cross Elasticity

** Gigawatt-hours = millions of kilowatt-hours (included in Saving)

*** Saving outweighs additional cost plus single-rate metering net cost

****Similar to Run 4 but using 5% discount factor

peak rates. It makes both rates available to anyone who would consume sufficient off-peak energy to save him more than the additional metering costs. It provides incentive for technological development of new equipment or processes which can use the rate structure to advantage. Within the limits of accuracy of this study, optional use of two-rate metering, in addition to providing the above benefits, would save from 0.5 to 122 million 1978 dollars in costs over the period from 1978 to 2000.

2. Compulsory Two-Rate Metering

Implementation of compulsory two-rate metering may result in a loss of up to 35 million 1978 dollars, or a saving up to 638 million dollars over the period from 1978 to 2000, depending on the rate differential and the elasticities involved. Thus it may be more costly than the optional system under certain conditions. However, it will induce equal or greater energy conservation than the optional system, because it covers all customers including those with small responses, as well as those with a sufficiently large response to offset the additional customer charge for the two-rate meter.

J. RECOMMENDATIONS

Based on the above conclusions, it is therefore recommended that

1. *A study should be conducted to test two-rate metering in actual use on a sufficiently large scale to determine residential customer response to peak and off peak rates based on marginal costs.*

2. *Consideration should be given to offering optional peak and off-peak rates, or two-rate metering, to customers who consume a relatively large amount of their energy at off-peak hours, and may feel that they are presently subsidizing peak users. Consideration should also be given to providing an incentive to technological innovation leading to future lower costs for producing electricity, and conserving resources.*

3. *Consideration should be given to implementing two-rate metering on a broad basis if the study suggested in recommendation 1 indicates that customer response is sufficient to ensure a greater benefit than with optional two-rate metering.*

Effect of Inclusion of Omitted Factors

Increase Cost of Two-Rate Metering

Unreliability of Two-Rate Meters (sensitivity to testing 2RM cost = .021)

Additional Statistical Analysis

Rate Readjustments (function of valley filling which is less than 5 per cent)

Additional Electric Heating Load due to cross price elasticities (hard to estimate)

Run 1-6

BASIC ASSUMPTIONS:
STUDY PERIOD=1978 TO 2000
INITIAL NUMBER OF CUSTOMERS=2212.THOUSAND
CUST GROWTH RATE= 2.28%/YR
INITIAL SYSTEM LOAD= 18.3 GW
SYSTEM LOAD GROWTH= 6.8%/YR
CHANGE TO 100% 2R METERING IN 10 YRS
ESCALATION RATE= 8.5%/YR
INTEREST RATE=12.00%/YR
NEW 13 A-BASE METER=$38.98
NEW 1R S-BASE METER=$29.65
NEW 2R METER=$160.00
CHANGE FROM 1R TO 2R METER=$20.00/CUST
SALVAGE OLD METER=($14.82-OPT),($0.00-CONV)
READING AND BILLING 1R=$12.99/YR
READING AND BILLING 2R=$15.09/YR
REPROGRAMMING COMPUTER=$400000.00
TESTING 1R METER=$18.00
TESTING 2R METER=$25.00

RESETTING CLOCK IN 2R METER=$ 2.00
PROB OF OUTAGE REQ RESET= .10/YR
STORAGE HEATER=$2500.00
STORAGE HEATING POTENTIAL=.59
CAPITAL COST OF SYSTEM CAPACITY=$802.10/KW
COST OF PEAK ENERGY=$ 1.96 CENTS/KWHR
COST OF OFF-PEAK ENERGY=$ 1.40 CENTS/KWHR
PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
DEMAND SAVING PER STORAGE HEATER= 6.3 KW
ELECTRIC HTG LOAD=29.60 MWHR/YR
ELECTRIC HTG SATURATION=.10
ELEC HTG ELASTICITY=-0.20
AVG COINC PEAK DEMAND=2.67 KW/CUST
AVG PEAK ENERGY= 5.31 MWHR/CUST
AVG OFF-PEAK ENERGY= 4.53 MWHR/CUST
SINGLE RATE= 2.91 CENTS/KWHR
RATE DIFF = 0.70 CENTS/KWHR

CONTINUATION WITH SINGLE-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	19901.	2164.	2384.	2626.	2894.	3198.	3516.	2731.	3038.	3365.	3732.	4142.	4296.	5100.	5668.	6281.	6970.	7315.	8584.	9526.	10572.	11732.	13019.	16026.
READING AND BILLING 1R	591685.	28411.	31532.	34992.	38832.	43093.	47822.	53070.	58894.	65357.	72529.	80488.	89321.	99122.	108000.	122201.	134567.	150133.	166830.	185138.	205454.	228200.	253021.	280787.
CHECKING 1R METERS	14659.	0.	0.	0.	0.	0.	0.	0.	689.	765.	849.	942.	1043.	1160.	1288.	1428.	1585.	1759.	1952.	2166.	2404.	2668.	2958.	3285.
RECALIBRATING 1R METERS	14438.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	9024.	8132.	9024.	10015.	11114.	12333.	13568.	15188.	16655.	18705.
YEARLY COST	630683.	30577.	33915.	37618.	41726.	46283.	51338.	55801.	62613.	69484.	77109.	85571.	94962.	105383.	116947.	137912.	151047.	169842.	188480.	209163.	232116.	257588.	285856.	1425152.
PRESENT VALUE	630683.	30577.	30282.	29989.	29700.	29414.	29130.	28270.	28323.	28064.	27806.	27552.	27299.	27049.	26801.	28220.	27961.	27705.	27451.	27199.	26950.	26703.	26459.	11778.

NET 1978 COST=$ 630.683 MILLION

Run 1

PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 0.70 CENTS/KWHR

OPTIONAL TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 2R METERS																								
READING AND BILLING 2R																								
CHECKING 2R METERS																								
RECALIBRATING 2R METERS																								
REPROGRAMMING BILLING																								
NEW 2R METERS																								
INSTALLATION LESS SALVAGE																								
READING AND BILLING 2R																								
CHECKING 2R METERS																								
RECALIBRATING 2R METERS																								
RESETTING 2R TIMERS																								
STORAGE HEATING																								
LOAD SHIFT																								
CONSERVATION																								
PEAK REDUCTION																								
YEARLY COST																								
PRESENT VALUE																								
YEARLY SAVING																								
PRESENT VALUE																								
PEAK REDUCTION (GW)																								
% PEAK REDUCTION																								
CONSERVATION (MWHR)																								
CHECKING 2R METERS																								
THOUS VALLEY/PEAK																								
THOUS OF TIMERS																								
THOUS STORAGE HEATERS																								

TOTAL CONSERVATION=   0.00% MILLION KWH

ADDITIONAL 1978 COST=$ 1.312 MILLION
     TOTAL 1978 COST=$ 631.994 MILLION
  TOTAL 1978 SAVINGS=$ 1.828 MILLION
  BENEFIT/COST RATIO=   1.394

NET 1978 COST=$ 632.166 MILLION

Run 1

PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 0.70 CENTS/KWHR

CONVERSION TO TWO-RATE METERING

TOTAL CONSERVATION=   3.156 MILLION KWH

ADDITIONAL 1978 COST=$ 410.873 MILLION
       TOTAL 1978 COST=$1041.555 MILLION
       TOTAL 1978 SAVING=$ 375.533 MILLION
       BENEFIT/COST RATIO=   0.914

       NET 1978 COST=$ 556.023 MILLION

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Run 2

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 0.70 CENTS/KWHR

OPTIONAL TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW IR METERS	19755.	2154.	2314.	2549.	2838.	3185.	3510.	2725.	3024.	3556.	3724.	4132.	4586.	5083.	5648.	6267.	6955.	7718.	8553.	9505.	10543.	11706.	12991.	-159642.
READING AND BILLING IR	590513.	28411.	31512.	34936.	38750.	42999.	47717.	52954.	58765.	65214.	72318.	80112.	89225.	98806.	109759.	121884.	135173.	150084.	165245.	187331.	205803.	227501.	252467.	280172.
CHECKING IR METERS	14458.	600.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	3278.
RECALIBRATING IR METERS	4216.	408.	0.	419.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	18664.
REPROGRAMMING BILLING	408.	408.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	798.	53.	378.	419.	89.	28.	29.	32.	36.	48.	44.	48.	5.	5.	4.	5.	5.	9.	10.	112.	125.	139.	154.	-3341.
INSTALLATION LESS SALVAGE	1362.	8.	23.	64.	95.	109.	122.	135.	150.	166.	184.	205.	227.	252.	280.	318.	344.	382.	424.	471.	522.	588.	643.	714.
READING AND BILLING 2R	12.	3.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING 2R METERS	31.	0.	0.	0.	0.	0.	0.	0.	5.	5.	3.	3.	3.	3.	4.	4.	5.	5.	6.	6.	7.	8.	9.	16.
RECALIBRATING 2R METERS	48.	-0.	0.	-0.	16.	16.	16.	14.	9.	5.	-3.	-16.	-17.	-19.	-22.	-24.	-27.	-29.	-33.	-36.	-40.	-45.	-50.	-116.
RESETTING 2R METERS	-44.	-0.	-0.	-0.	-1.	-2.	-4.	-6.	-9.	-12.	-14.	-16.	-17.	-19.	-22.	-24.	-31.	-29.	-33.	-36.	-40.	-45.	-58.	-152.
STORAGE HEATING	-176.	-0.	-0.	-0.	-1.	-4.	-8.	-14.	-20.	-25.	-29.	-33.	-47.	-41.	-22.	-58.	-62.	-88.	-657.	-76.	-165.	-94.	-94.	-116.
LOAD SHIFT	-1989.	0.	-0.	-0.	-2.	-4.	-8.	-14.	-28.	-357.	-385.	-431.	-480.	-533.	-591.	-656.	-728.	-888.	-897.	-995.	-1104.	-1360.	-1568.	-1509.
CONSERVATION																								
PEAK REDUCTION																								
YEARLY COST	631994.	31322.	34228.	37974.	41823.	46538.	51598.	55862.	62674.	69547.	77177.	85646.	95045.	105474.	117843.	138826.	153173.	169385.	188643.	209345.	232319.	285803.	286185.	159886.
PRESENT VALUE	631994.	31322.	30561.	30273.	29769.	29449.	29154.	28181.	28551.	28089.	27831.	27576.	27323.	27503.	26625.	28443.	27984.	27228.	27415.	27223.	26974.	26727.	25482.	21549.
YEARLY SAVING	-2249.	-0.	-0.	-1.	-2.	-4.	-12.	-20.	-33.	-151.	-488.	-488.	-534.	-533.	-688.	-738.	-588.	-733.	-998.	-1198.	-1229.	-1548.	-1598.	-1508.
PRESENT VALUE	-2249.	-0.	-0.	-1.	-2.	-4.	-10.	-18.	-13.	-151.	-154.	-155.	-154.	-152.	-151.	-149.	-148.	-147.	-145.	-144.	-143.	-141.	-148.	-133.
PEAK REDUCTION (MW)		0.	0.	0.	0.	0.	1.	1.	1.	2.	2.	2.	2.	2.	2.	2.	2.	2.	2.	2.	2.	2.	3.	3.
% PEAK REDUCTION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CONSERVATION (MWHRS)		0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.
% VALLEY/PEAK		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
THOUS OF IR METERS		5.	3.	5.	5.	5.	5.	6.	6.	6.	6.	6.	7.	7.	7.	7.	7.	7.	7.	7.	6.	6.	6.	6.
THOUS STORAGE HEATERS		0.	0.	1.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL CONSERVATION=   0.014 MILLION KWH

ADDITIONAL 1978 COST=$ 1.312 MILLION
     TOTAL 1978 COST=$ 631.994 MILLION
   TOTAL 1978 SAVING=$ 2.249 MILLION
   BENEFIT/COST RATIO=   1.715

NET 1978 COST=$ 629.746 MILLION

Run 2

CONVERSION TO TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW IR METERS	127521.	26654.	25803.	24653.	23097.	21143.	18713.	15745.	12165.	7896.	2853.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING IR		0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING IR METERS		0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
RECALIBRATING IR METERS	400.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
REPROGRAMMING BILLING	316599.	43355.	47058.	51057.	53575.	60081.	65188.	70723.	76742.	83264.	90142.	22349.	24801.	27925.	30543.	33895.	37615.	41742.	45121.	51406.	57048.	63508.	70255.	-172923.
NEW 2R METERS	376039.	4420.	4774.	5156.	5569.	5981.	6466.	6983.	7541.	8105.	8752.	93500.	103760.	115147.	127783.	141885.	157367.	174636.	193803.	215867.	238669.	264860.	293925.	326179.
INSTALLATION LESS SALVAGE	733201.	2844.	655.	12035.	18279.	25499.	33814.	43359.	54283.	138.	282.	459.	665.	902.	1174.	1408.	1842.	2249.	2711.	3089.	3519.	3789.	4112.	4563.
READING AND BILLING 2R	4311.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	175.4	1.8
CHECKING 2R METERS	8725.	27.	88.	159.	241.	338.	448.	575.	719.	885.	1075.	1259.	1375.	1526.	1694.	1879.	2086.	2315.	2569.	2854.	3163.	3510.	3896.	4324.
RECALIBRATING 2R METERS	7146.	37.	2.	2.	2.	4.	7.	9.	10.	12.	13.	14.	14.	15.	14.	7.	9.	7.	7.	7.	8.	8.	9.	-103.
RESETTING 2R TIMERS	37.	27.	-1.	-65.	-190.	-445.	-858.	-1427.	-2136.	-2972.	-3940.	-5047.	-6296.	-7665.	-9101.	-10538.	-11953.	-13383.	-14890.	-16534.	-18351.	-20365.	-22600.	-24923.
STORAGE HEATING		-6.	-16.	-65.	-190.	-445.	-858.	-1427.	-2136.	-2972.	-3940.	-5047.	-6296.	-7665.	-9101.	-10538.	-11953.	-13383.	-14890.	-16534.	-18351.	-20365.	-22600.	-24923.
LOAD SHIFT	-32021.	-3.	-35.	-136.	-401.	-937.	-1888.	-3307.	-4498.	-4261.	-3640.	-10613.	-13167.	-16448.	-19177.	-22199.	-25185.	-28192.	-31365.	-34658.	-38035.	-41689.	-45681.	-50034.
CONSERVATION	-67456.	-6.								-47254.	-62155.	-78297.	-96556.	-116581.	-137512.	-158679.	-179677.	-201022.	-223626.	-248804.	-275588.	-305027.	-339389.	-376631.
PEAK REDUCTION	-445125.	-9.																						
YEARLY COST	1041555.	76899.	84355.	93020.	102564.	113052.	124637.	137400.	151460.	167042.	184255.	175761.	138615.	145112.	161227.	179077.	208454.	224281.	258812.	280184.	312854.	349243.	389712.	-1372634.
PRESENT VALUE	1041555.	76899.	75320.	74155.	73023.	71847.	70773.	69611.	68513.	67455.	37971.	-31970.	-33976.	-33247.	-35954.	-36642.	-37993.	-39585.	-268805.	-36435.	-36126.	-36205.	-36075.	-35545.
YEARLY SAVING	-544603.	-9.	-51.	-201.	-592.	-1382.	-2664.	-4435.	-5013.	-5745.	-33706.	-35976.	-115698.	-140314.	-165783.	-191416.	-242394.	-259773.	-269805.	-299669.	-325591.	-369093.	-403518.	-455247.
PRESENT VALUE	-544603.	-9.	-46.	-160.	-421.	-879.	-1513.	-2247.	-3001.	-2269.	-26828.	-33026.	-33370.	-36015.	-37993.	-39167.	-39611.	-39773.	-39387.	-38969.	-38616.	-38263.	-37912.	-37565.
PEAK REDUCTION (MW)	4.	0.0	10.	19.	37.	65.	105.	152.	204.	257.	318.	350.	409.	455.	495.	526.	549.	566.	581.	594.	608.	622.	636.	650.
% PEAK REDUCTION	0.0	0.0	0.0	0.1	0.2	0.5	0.4	0.6	0.7	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.8
CONSERVATION (MWHRS)	65.0	65.1	2.	6.1	16.	35.	61.	94.	138.	166.	203.	240.	276.	318.	359.	361.	378.	390.	400.	409.	419.	428.	438.	448.
% VALLEY/PEAK	271.	271.	65.1	65.1	65.2	65.4	65.5	65.7	65.9	66.0	66.1	66.2	66.3	66.4	66.4	66.4	66.3	66.3	66.2	66.2	66.1	66.1	65.0	66.0
THOUS 2R METERS			512.	813.	1884.	1355.	1626.	1897.	2168.	2439.	2710.	2771.	2835.	2899.	2965.	3031.	3102.	3173.	3243.	3319.	3395.	3472.	3551.	3632.
THOUS STORAGE HEATERS		271.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL CONSERVATION=   5.548 MILLION KWH

ADDITIONAL 1978 COST=$ 410.873 MILLION
      TOTAL 1978 COST=$104.555 MILLION
    TOTAL 1978 SAVING=$ 544.603 MILLION
    BENEFIT/COST RATIO=   1.325

NET 1978 COST=$ 496.953 MILLION

Run 3

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.30
RATE DIFF = 0.70 CENTS/KWHR

OPTIONAL TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	19755.	2154.	2314.	2549.	2878.	3185.	3510.	2725.	3024.	3356.	3724.	4152.	4586.	5089.	5648.	6267.	6957.	7719.	8565.	9505.	10549.	11706.	12991.	13962.
READING AND BILLING 1R	590513.	28411.	31512.	34936.	38750.	42999.	47717.	52954.	58765.	65214.	72578.	80312.	89125.	98906.	109759.	121884.	135171.	150004.	166465.	184735.	205205.	227081.	252467.	280112.
RECHECKING 1R METERS	4652.	0.	0.	0.	0.	0.	0.	0.	0.	765.	848.	940.	1043.	1157.	1284.	1425.	1582.	1755.	1948.	2161.	2399.	2662.	2954.	5278.
RECALIBRATING 1R METERS	14416.	0.	0.	0.	0.	0.	0.	0.	689.															
REPROGRAMMING/BILLING	1400.	400.	0.	419.	89.	28.	29.	32.	36.	40.	44.	49.	54.	60.	67.	74.	82.	90.	101.	112.	125.	138.	154.	18664.
NEW 2R METERS	790.	53.	378.	6.	95.	189.	122.	135.	130.	166.	184.	205.	227.	252.	280.	310.	344.	382.	424.	471.	522.	580.	643.	714.
INSTALLATION LESS SALVAGE	1350.	3.	23.	6.	9.	8.	8.	2.	8.	2.	8.	8.	3.	3.	4.	4.	5.	5.	6.	7.	7.	8.	9.	10.
READING AND BILLING 2R	312.	3.	0.	0.	0.	8.	8.	14.	9.	1.	3.	3.	3.	3.	4.	4.	5.	5.	6.	7.	7.	8.	9.	57.
CHECKING 2R METERS	31.	3.	0.	1.	10.	16.	18.	17.	17.	17.	17.													
RECALIBRATING 2R METERS	18.	0.	-0.	-0.	-1.	6.	18.	14.	-7.	-5.	-3.	-23.	-47.	-25.	-4.	-4.	-38.	-48.	-52.	-68.	-88.	-64.	-71.	-116.
RESETTING 2R TIMERS	21.	0.	0.	-1.	1.	6.	18.																	
LOAD SHIFT	-48.	-8.	-0.	-1.	-1.	-4.	-18.	-17.	-25.	-12.	-6.	-42.	-47.	-28.	-38.	-54.	-71.	-79.	-97.	-120.	-153.		-17.	
CONSERVATION	-225.	-8.	-0.	-0.	-2.	-5.	-8.	-27.	-38.	-399.	-458.	-513.	-571.	-634.	-704.	-781.	-867.	-962.	-1068.	-1185.	-1315.	-1460.	-1620.	-1798.
PEAK REDUCTION	-2568.	-8.																						
YEARLY COST	631994.	31022.	34228.	37974.	41823.	46338.	51198.	55862.	62674.	69547.	77177.	85646.	95045.	104474.	117049.	138026.	151173.	159885.	189644.	209563.	233319.	257813.	286105.	1598056.
PRESENT VALUE	631994.	31022.	30561.	30273.	29769.	29449.	29164.	28301.	28351.	28039.	27833.	27573.	27321.	27073.	26825.	28474.	27934.	27238.	27417.	27025.	26974.	26277.	26402.	
YEARLY SAVING	-2713.	-0.	-0.	-1.	-5.	-8.	-16.	-27.	-38.	-448.	-515.	-578.	-643.	-715.	-793.	-880.	-997.	-1084.	-1203.	-1335.	-1481.	-1644.	-1824.	-2024.
PRESENT VALUE	-2713.	-0.	-0.	-1.	-2.	-5.	-9.	-14.	-17.	-181.	-186.	-186.	-185.	-183.	-182.	-180.	-178.	-177.	-175.	-174.	-172.	-170.	-169.	-163.
PEAK REDUCTION (MW)		0.	0.	1.	1.	2.	0.	2.	2.	2.	2.	2.	3.	3.	3.	3.	3.	3.	3.	3.	3.	3.	3.	3.
% PEAK REDUCTION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	2.0	2.0
CONSERVATION (MWHRS)		0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
THOUS VALLEY/PEAK		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
THOUS OF 1R METERS		0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
THOUS STORAGE HEATERS		0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL CONSERVATION=   0.018 MILLION KWH

ADDITIONAL 1978 COST=$ 1.312 MILLION
     TOTAL 1978 COST=$ 631.994 MILLION
  TOTAL 1978 SAVING=$ 2.713 MILLION
  BENEFIT/COST RATIO=   2.068

     NET 1978 COST=$ 629.281 MILLION

Run 3

```
PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.30
RATE DIFF = 0.70 CENTS/KWHR
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CONVERSION TO TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	127521.	26654.	25803.	24633.	23097.	21143.	18715.	15745.	12165.	7896.	2850.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 1R	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
RECALIBRATING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
REPROGRAMMING BILLING	400.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	316999.	43353.	47038.	51037.	55375.	60081.	65188.	70729.	76741.	83264.	92342.	22349.	24801.	27523.	30543.	33895.	37615.	41742.	46323.	51406.	57048.	63308.	70255.	1172923.
INSTALLATION LESS SALVAGE	37689.	4420.	4774.	5156.	5559.	5987.	6466.	6983.	7541.	8185.	8732.	93580.	103760.	115147.	127783.	141386.	157167.	174636.	193800.	215962.	238659.	264860.	293925.	326179.
READING AND BILLING 2R	533201.	2044.	654.	1203.	18279.	24499.	33861.	43555.	54283.	138.	282.	459.	665.	902.	1174.	1486.	1842.	2249.	2711.	3289.	3339.	3705.	4112.	4563.
CHECKING 2R METERS	43517.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1535.	3332.	5422.	7844.	10639.	13851.	17534.	21742.
RECALIBRATING 2R METERS	8725.	27.	86.	159.	242.	358.	448.	575.	719.	885.	1073.	1239.	1375.	1526.	1694.	1879.	2085.	2315.	2569.	2850.	3163.	3510.	3896.	4375.
RESETTING 2R TIMERS	7146.	27.	86.	159.	242.	358.	448.	575.	719.	885.	1073.	1239.	1375.	1526.	1694.	1879.	12.	14.	16.	17.	7.	0.	0.	0.
STORAGE HEATING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
LOAD SHIFT	-46198.	-4.	-24.	-91.	-273.	-642.	-1238.	-2059.	-3081.	-4288.	-5634.	-7282.	-9084.	-11055.	-13138.	-15204.	-17245.	-19308.	-21481.	-23855.	-26476.	-29382.	-32606.	-36185.
CONSERVATION	-86015.	-8.	-44.	-173.	-512.	-1195.	-2385.	-3834.	-5717.	-7983.	-10534.	-13557.	-16913.	-20591.	-24446.	-28307.	-32189.	-35948.	-39999.	-44415.	-49294.	-54705.	-60706.	-67570.
PEAK REDUCTION	-599478.	-12.	-61.	-213.	-560.	-1167.	-2010.	-2986.	-3989.	-5063.	-35743.	-104832.	-129621.	-156882.	-185559.	-214084.	-242224.	-271384.	-301917.	-335237.	-372264.	-412902.	-458214.	-508498.
YEARLY COST	1041555.	76899.	84358.	93220.	102564.	113852.	124637.	137400.	151460.	167842.	144755.	117561.	136616.	145112.	161207.	179877.	200845.	224281.	258812.	280184.	312864.	349043.	389730.	1372604.
PRESENT VALUE	1041555.	76899.	73320.	74155.	73203.	71843.	70122.	69511.	68513.	67465.	64444.	37851.	37549.	36945.	36943.	36643.	36622.	36585.	36532.	36435.	36326.	36205.	36073.	878.
YEARLY SAVING	-731691.	-112.	-68.	-267.	-786.	-1837.	-3543.	-5893.	-8818.	-75334.	-99117.	-125671.	-155613.	-188452.	-222935.	-257595.	-291879.	-326639.	-363399.	-403507.	-447834.	-496988.	-551528.	-612052.
PRESENT VALUE	-731691.	-112.	-61.	-213.	-560.	-1167.	-2010.	-2986.	-3989.	-30426.	-35743.	-44736.	-48371.	-48371.	-51891.	-52709.	-53335.	-53282.	-52927.	-52472.	-51997.	-51521.	-51047.	-50582.
PEAK REDUCTION (MW)	4.	0.0	11.	22.	45.	83.	136.	200.	270.	341.	413.	482.	549.	612.	667.	710.	741.	764.	784.	802.	820.	839.	858.	878.
% PEAK REDUCTION	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.7	0.9	1.1	1.3	1.4	1.5	1.5	1.6	1.6	1.5	1.5	1.4	1.3	1.3	1.2	1.2	1.1
CONSERVATION (MWHRS)	0.	0.	1.	2.	20.	44.	78.	126.	165.	212.	259.	306.	352.	395.	432.	461.	482.	497.	510.	522.	534.	546.	558.	571.
% VALLEY/PEAK	65.0	65.1	65.1	65.1	65.2	65.3	65.5	65.7	65.9	66.4	66.5	66.6	66.5	66.8	66.9	66.9	66.8	66.6	66.7	65.6	66.6	66.5	66.4	66.4
THOUS OFF 1R METERS	211.	211.	542.	813.	1356.	1356.	1626.	1897.	2170.	2443.	2716.	2771.	2845.	2899.	2965.	3031.	3102.	3170.	3245.	3316.	3395.	3472.	3551.	3632.
THOUS STORAGE HEATERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

```
TOTAL CONSERVATION=   7.074  MILLION KWH

ADDITIONAL 1978 COST=$ 410.873 MILLION
     TOTAL 1978 COST=$1041.555 MILLION
   TOTAL 1978 SAVING=$ 731.691 MILLION
  BENEFIT/COST RATIO=    1.781

NET 1978 COST=$ 309.865 MILLION
```

Run 4

PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWHR

OPTIONAL TWO-RATE METERING

The body of this page is a large wide numeric table with the following column headers:

TOTAL, 1978, 1979, 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000

Row labels:

Row label	TOTAL
NEW IR METERS	14318.
READING AND BILLING IR	549999.
CHECKING IR METERS	42598.
RECALIBRATING IR METERS	13479.
REPROGRAMMING BILLING	408.
NEW 2R METERS	33551.
INSTALL METER LESS SALVAGE	410.
READING AND BILLING 2R	517788.
CHECKING 2R METERS	502.
RECALIBRATING 2R METERS	1312.
RESETTING 2R TIMERS	766.
STORAGE HEATING	2174.
LOAD SHIFT	-3760.
CONSERVATION	-6888.
PEAK REDUCTION	-90828.
YEARLY COST	672985.
PRESENT VALUE	670985.
YEARLY SAVING	-885676.
PRESENT VALUE	-1088676.
PEAK REDUCTION (MW)	
% PEAK REDUCTION	
CONSERVATION (MWHRS)	
% VALLEY/PEAK	
THOUS OF IIR METERS	
THOUS STORAGE HEATERS	

TOTAL CONSERVATION=   0.485 MILLION KWH

ADDITIONAL 1978 COST=$ 40.303 MILLION
TOTAL 1978 COST=$ 670.985 MILLION
TOTAL 1978 SAVING=$ 108.676 MILLION
BENEFIT/COST RATIO=   2.696

NET 1978 COST=$ 562.310 MILLION

Run 4

PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWHR

CONVERSION TO TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 1R	12752.	2665.	2580.	2463.	2309.	2114.	1871.	15745.	12165.	7896.	2850.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
RECALIBRATING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
REPROGRAMMING BILLING	400.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	315599.	43323.	47038.	51037.	55375.	60881.	65188.	70720.	76741.	83264.	90342.	93502.	24801.	275924.	305443.	335695.	37615.	417742.	46323.	514206.	57048.	63308.	70255.	0.
READING AND BILLING 2R	315629.	43420.	4774.	5156.	52569.	5981.	6466.	6983.	7541.	8105.	8752.	459.	665.	115147.	1174.	1486.	1573567.	174636.	193897.	215657.	233669.	264860.	293925.	3261379.
INSTALLATION LESS SALVAGE	539201.	2043.	6654.	12053.	18279.	25499.	33614.	43559.	54283.	66749.	80944.	93502.	103760.	982.	12778.	141805.	18422.	12293.	5422.	37459.	5339.	3705.	412.	1553.
CHECKING 2R METERS	4317.	0.	0.	0.	0.	0.	0.	0.	130.	130.	282.	459.	665.	1526.	174.	1486.	1535.	3332.	2569.	7844.	10653.	13851.	17534.	21742.
RECALIBRATING 2R METERS	8725.	0.	0.	0.	0.	0.	0.	575.	719.	885.	1073.	1239.	1175.	0.	1694.	1979.	2086.	2315.	2569.	2850.	3163.	3510.	3896.	4323.
RESETTING 2R TIMERS	7146.	2.	88.	139.	96.	198.	295.	396.	458.	522.	571.	616.	659.	665.	625.	578.	414.	358.	295.	302.	328.	362.	422.	2177.
STORAGE HEATING	1688.	2.	11.	37.	0.	318.	448.	575.	719.	885.	1073.	1239.	1175.	1526.	1694.	1979.	-1245.	-14157.	-17393.	-17497.	-17497.	-21944.	-23308.	-25523.
LOAD SHIFT	-33875.	-3.	-17.	-68.	-206.	-471.	-908.	-1510.	-2259.	-3144.	-4168.	-5339.	-6561.	-8189.	-9627.	-11140.	-20710.	-22910.	-25491.	-28306.	-31413.	-34564.	-37893.	-42335.
CONSERVATION	-54820.	-5.	-28.	-111.	-326.	-762.	-1469.	-2444.	-3656.	-5088.	-6740.	-8644.	-10779.	-13121.	-15589.	-18340.	-1522.48.	-23335.	-25187.	-18303.	-28397.	-34564.	-37893.	-42335.
PEAK REDUCTION	-453282.	-8.	-41.	-143.	-376.	-784.	-1349.	-2003.	-2616.	-3230.	-3727.	-3487.	-98729.	-116350.	-139318.	-161144.	-139318.	-2133558.	-2.31042.	-2518378.	-2795437.	-3102518.	-3442862.	-3.52041.
YEARLY COST	1043206.	76901.	84569.	93056.	102657.	113238.	124930.	137787.	151918.	167552.	184913.	118163.	131256.	147563.	161819.	179595.	200859.	224603.	251121.	280479.	313185.	349557.	357103.	-1182595.
PRESENT VALUE	1043206.	76971.	75329.	74184.	73070.	71965.	70898.	69827.	68720.	67618.	6975.	30747.	32193.	33414.	3085.	3574.	36659.	36638.	35574.	36473.	36315.	36242.	37110.	-114495.
YEARLY SAVING	-541978.	-8.	-46.	-173.	-328.	-1233.	-2377.	-3555.	-5916.	-71517.	-93128.	-91449.	-116163.	-139982.	-165045.	-193425.	-215437.	-240997.	-268087.	-297667.	-330366.	-366226.	-406360.	-61508.
PRESENT VALUE	-541978.	-8.	-41.	-143.	-328.	-784.	-1349.	-2003.	-2616.	-2330.	-271103.	-30487.	-33393.	-35550.	-37824.	-38944.	-39359.	-39312.	-39245.	-38709.	-38358.	-36807.	-37659.	-37314.
PEAK REDUCTION (MW)		6.	13.	24.	43.	72.	113.	161.	213.	267.	328.	370.	418.	464.	503.	534.	557.	574.	589.	603.	616.	630.	645.	660.
% PEAK REDUCTION		0.0	0.1	0.1	0.1	0.3	0.4	0.4	0.7	0.9	0.9	1.0	2.1	1.2	1.2	1.2	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9
CONSERVATION (MWHRS)		65.	65.1	65.2	65.3	65.4	65.6	65.8	66.0	65.1	65.0	66.4	66.4	66.5	66.5	66.5	66.5	66.4	66.4	66.3	66.2	66.2	66.1	66.1
THOUS OF 1TR METERS		271.	542.	813.	1084.	1355.	1626.	1897.	2168.	2439.	2710.	2771.	2833.	2899.	2965.	3033.	3102.	3173.	3245.	3319.	3395.	3472.	3551.	3632.
THOUS STORAGE HEATERS		0.	0.	0.	0.	0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.

TOTAL CONSERVATION=   4.509 MILLION KWH

ADDITIONAL 1978 COST=$ 412.523 MILLION
      TOTAL 1978 COST=$1043.206 MILLION
    TOTAL 1978 SAVING=$ 541.978 MILLION
    BENEFIT/COST RATIO=   1.314

NET 1978 COST=$ 501.228 MILLION

Run 5

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWHR

OPTIONAL TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	14348.	1741.	0.	0.	2196.	2971.	3287.	2477.	2749.	1851.	3385.	3757.	4169.	4627.	5134.	5698.	6323.	7017.	7787.	8642.	9590.	10642.	11810.	13081.
READING AND BILLING 1R	541939.	28322.	30681.	32640.	35343.	35394.	43358.	48140.	53424.	52273.	61733.	53013.	81025.	89917.	99784.	110735.	122886.	134372.	151157.	167944.	185374.	206826.	229523.	254718.
CHECKING 1R METERS	14296.	0.	0.	0.	0.	0.	0.	0.	0.	768.	829.	860.	948.	1052.	1168.	1296.	1438.	1596.	1771.	1965.	2181.	2428.	2686.	2988.
RECALIBRATING 1R METERS	13419.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	8123.	8996.	9543.	10148.	11189.	12416.	13778.	15290.	16968.
REPROGRAMMING BILLING	404.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	33551.	2268.	1637.	1797.	3766.	1183.	1234.	1365.	1519.	1685.	1870.	2076.	2303.	255.	2817.	3148.	3493.	3877.	4302.	4774.	5298.	5879.	652.	141803.
INSTALLATION LESS SALVAGE	410.	0.	223.	225.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 2R	57788.	107.	988.	271.	4053.	4645.	5159.	5725.	6354.	7051.	7825.	8683.	9636.	10694.	11867.	13169.	14614.	16218.	17998.	19975.	22165.	24597.	27296.	32892.
CHECKING 2R METERS	502.	0.	0.	0.	0.	0.	0.	0.	0.	7.	56.	114.	135.	150.	166.	184.	204.	222.	252.	279.	309.	344.	393.	424.
RECALIBRATING 2R METERS	1332.	1.	0.	0.	0.	0.	0.	76.	84.	93.	104.	115.	128.	142.	157.	175.	194.	215.	239.	265.	294.	326.	362.	2413.
RESETTING 2R TIMERS	766.	1.	13.	36.	462.	63.	820.	642.	399.	218.	146.	134.	143.	158.	175.	194.	215.	239.	265.	294.	326.	362.	402.	401.
STORAGE HEATING	2174.	-0.	61.	212.	-42.	721.	0.	0.	84.	0.	104.	115.	128.	-178.	-135.	-194.	-215.	-239.	-265.	-294.	-326.	-362.	402.	-5238.
LOAD SHIFT	-9074.	-1.	-3.	-13.	-111.	-111.	-232.	-393.	-564.	-715.	-840.	-949.	-1059.	-1176.	-1305.	-1449.	-1683.	-3768.	-4170.	-4628.	-5136.	-5786.	-6525.	-7345.
CONSE REDUCTION	-108689.	-1.	-6.	-27.	-89.	-234.	-488.	-829.	-1188.	-1566.	-2211.	-20073.	-23304.	-24779.	-33051.	-39057.	-43355.	-48111.	-53391.	-59259.	-65751.	-72957.	-83934.	-89868.
PEAK REDUCTION	-1118421.	0.	0.	0.	0.	0.	0.	0.	-28065.	-28065.	-22917.	-25679.	-28577.	31719.	-35203.	-39866.	-43553.	-48111.	-53391.	-59259.	-65751.	-72957.	-83934.	-89868.
YEARLY COST	670985.	32660.	48017.	53673.	45873.	48675.	53938.	58451.	62218.	72152.	79987.	88752.	98488.	109294.	121288.	142730.	158415.	175598.	195459.	216914.	240718.	261134.	294449.	291367.
PRESENT VALUE	670985.	32860.	42872.	42708.	32652.	30934.	30601.	29603.	23591.	29141.	28444.	28126.	28113.	28053.	27796.	29205.	28942.	28202.	28455.	28297.	27949.	27691.	27437.	1843.
YEARLY SAVING	-134184.	-1.	-9.	-14.	-132.	-340.	-728.	-1222.	-1712.	-2228.	-2549.	-28526.	-35372.	-35372.	-39257.	-43566.	-48342.	-53653.	-59540.	-66074.	-73325.	-81572.	-93501.	-100211.
PRESENT VALUE	-134184.	-1.	-8.	-32.	-194.	-226.	-409.	-619.	-793.	-9002.	-3285.	-9217.	-9158.	-9079.	-8997.	-8914.	-8833.	-8752.	-8672.	-8592.	-8514.	-8436.	-8358.	-8282.
PEAK REDUCTION (MW)	3.	.3	22.	42.	50.	59.	72.	87.	93.	109.	114.	118.	121.	124.	127.	130.	132.	136.	139.	142.	145.	148.	152.	155.
% PEAK REDUCTION	0.0	0.0	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.2
CONSERVATION (MWHRS)	65.0	65.0	65.2	65.4	65.4	65.4	65.5	65.5	65.6	65.6	65.5	65.5	65.5	65.5	65.5	65.4	65.4	65.4	65.4	65.4	65.4	65.3	65.3	65.3
THOUS VALLEY METERS	14.	14.	107.	201.	219.	223.	230.	235.	241.	246.	252.	257.	263.	269.	275.	282.	288.	295.	301.	308.	315.	322.	334.	337.
THOUS STORAGE HEATERS	0.	0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.

TOTAL CONSERVATION=   0.851 MILLION KWH

ADDITIONAL 1978 COST=$ 40.303 MILLION
     TOTAL 1978 COST=$ 670.985 MILLION
   TOTAL 1978 SAVING=$ 134.184 MILLION
   BENEFIT/COST RATIO=   3.329

NET 1978 COST=$ 536.801 MILLION

Run 5

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWHR

CONVERSION TO TWO-RATE METERING

TOTAL CONSERVATION=   7.926 MILLION KWH

ADDITIONAL 1978 COST=$ 412.523 MILLION
     TOTAL 1978 COST=$1043.206 MILLION
  TOTAL 1978 SAVING=$ 723.506 MILLION
     BENEFIT/COST RATIO=   1.899

NET 1978 COST=$ 259.700 MILLION

Run 6

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.30
RATE DIFF = 1.00 CENTS/KWHR

OPTIONAL TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS																								
READING AND BILLING 1R																								
CHECKING 1R METERS																								
RECALIBRATING 1R METERS																								
REPROGRAMMING BILLING																								
NEW 2R METERS																								
INSTALLATION LESS SALVAGE																								
READING AND BILLING 2R																								
CHECKING 2R METERS																								
RECALIBRATING 2R METERS																								
RESETTING 2R TIMERS																								
STORAGE HEATING																								
LOAD SHIFT																								
CONSERVATION																								
PEAK REDUCTION																								
YEARLY COST																								
PRESENT VALUE																								
YEARLY SAVING																								
PRESENT VALUE																								
PEAK REDUCTION (MW)																								
% PEAK REDUCTION																								
CONSERVATION (MWHRS)																								
% CONSERVATION																								
THOU VALLEY/PEAK																								
THOUS STORAGE HEATERS																								

TOTAL CONSERVATION=   1.085   MILLION KWH

ADDITIONAL 1978 COST=$ 40.303 MILLION
    TOTAL 1978 COST=$ 670.985 MILLION
  TOTAL 1978 SAVING=$ 162.330 MILLION
 BENEFIT/COST RATIO=   4.028

NET 1978 COST=$ 508.655 MILLION

Run 6

PEAK ELASTICITY=-0.50
OFF-PEAK ELASTICITY=-0.30
PEAK/OFF-PEAK CROSS ELASTICITY= 0.30
RATE DIFF = 1.00 CENTS/KWHR

CONVERSION TO TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 1R	127521.	26654.	25801.	24653.	23097.	21143.	18715.	15745.	12165.	7896.	2956.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
RECALIBRATING 1R METERS	400.	400.																						
REPROGRAMMING BILLING																								
NEW 2R METERS	316599.	43353.	47058.	51053.	55175.	60061.	65198.	70729.	76741.	83264.	98342.	22349.	24801.	27521.	30544.	33895.	37615.	41742.	46123.	51486.	57248.	63308.	70255.		
INSTALLATION LESS SALVAGE	37609.	4420.	4774.	5156.	5569.	5987.	6466.	6983.	7541.	8105.	8125.	9358.	665.	1175147.	127783.	141805.	157367.	174616.	193800.	215067.	238669.	264860.	293925.	326179.
READING AND BILLING 2R	53920.	2044.	654.	1203.	1825.	25499.	33815.	43555.	54293.	66749.	80944.	2882.	139.	982.	1174.	1486.	0.	2249.	5422.	3809.	3705.	3785.	3412.	563.
CHECKING 2R METERS	4111.												459.	1526.	1694.	1879.	2086.	2315.	2569.	2850.	3163.	3510.	3896.	4323.
RECALIBRATING 2R METERS	8725.	27.	88.	155.	242.	338.	448.	575.	718.	882.	1073.	1235.	1175.	665.	625.	530.	414.	338.	295.	382.	328.	362.	402.	0.
RESETTING 2R TIMERS	7146.	2.	-11.	-33.	-92.	-190.	-286.	-396.	-572.		971.	616.	654.	-15799.	-18757.	-21720.	-24633.	-27583.	-30651.	-34079.	-37723.	-41935.	-46581.	-51193.
STORAGE HEATING	-1688.	-4.	-34.	-137.	-332.	-917.	-1768.	-2942.	-4402.	-6126.	-6121.	-10402.	-12977.	-29415.	-34923.	-40436.	-45810.	-51154.	-56451.	-63456.	-70222.	-78149.	-85726.	-96243.
LOAD SHIFT	-65198.	-11.	-63.	-248.	-731.	-1707.	-3293.	-5477.	-8195.	-11405.	-15119.	-19368.	-24161.											
CONSERVATION	-122878.																							
PEAK REDUCTION	-861998.	-17.	-87.	-304.	-800.	-1668.	-2872.	-4265.	-5698.	-43691.	-51267.	-58100.	-64248.	-494170.	-75701.	-76816.	-76526.	-76526.	-76816.	-73563.	-74680.	-73997.	-73328.	-72648.
YEARLY COST	1043206.	76901.	84369.	93056.	102657.	113238.	124950.	137787.	151918.	167552.	184813.	181163.	118163.	145763.	161819.	179555.	208859.	224603.	251121.	280479.	315185.	349597.	390123.	1300795.
PRESENT VALUE	1043206.	76901.	75329.	74184.	73870.	71965.	70888.	69807.	68720.	67672.	66545.	38845.	37733.	37414.	37085.	36596.	36396.	36638.	36571.	36471.	36563.	36242.	36118.	-1140796.
YEARLY SAVING	1050775.	-17.	-97.	-381.	-1123.	-2624.	-5061.	-8419.	-12597.	-108176.	-142534.	-184476.	-223492.	-70815.	-320184.	-413210.	-452915.	-459115.	-523032.	-539513.	-643203.	-718800.	-792153.	-876061.
PRESENT VALUE	-1050775.	-17.	-87.	-504.	-800.	-1668.	-2872.	-4265.	-5698.	-43591.	-51267.	-58100.	-64248.	-434108.	-73178.	-75703.	-75701.	-76526.	-76816.	-73563.	-74680.	-73997.	-73328.	-72648.
PEAK REDUCTION (MW)	6.	0.0	15.	32.	64.	119.	195.	288.	388.	490.	594.	693.	789.	880.	959.	1021.	1066.	1099.	1127.	1133.	1184.	1297.	1234.	1062.
% PEAK REDUCTION	0.0	0.1	0.2	0.3	0.3	0.5	0.8	1.1	1.3	1.6	1.8	2.0	2.1	2.2	2.2	2.0	2.1	1.9	1.8	1.7	1.6		
CONSERVATION (MWHRS)	1.	3.	11.	29.	63.	112.	171.	266.	385.	577.	474.	503.	562.	642.	657.	688.	710.	728.	742.	763.	788.	798.	816.	
VALLEY/PEAK	65.1	65.1	65.2	65.4	65.7	66.0	66.3	67.0	67.6	67.2	67.7	67.7	67.8	67.7	67.7	67.6	67.5	67.4	67.3	67.2	67.1	67.0		
THOUS OTHER METERS	271.	542.	815.	1081.	1355.	1636.	1897.	2168.	2439.	2710.	2771.	2835.	2899.	2965.	3033.	3102.	3173.	3245.	3319.	3395.	3472.	3551.	3632.	
THOUS STORAGE HEATERS	0.	0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	

TOTAL CONSERVATION= 10.106 MILLION KWH

ADDITIONAL 1978 COST=$ 412.523 MILLION
      TOTAL 1978 COST=$1043.206 MILLION
    TOTAL 1978 SAVING=$1050.775 MILLION
   BENEFIT/COST RATIO= 2.547

NET 1978 COST=$ -7.569 MILLION

Run 7   5% discount rate

BASIC ASSUMPTIONS:
STUDY PERIOD=1978 TO 2000
INITIAL NUMBER OF CUSTOMERS=2212.THOUSAND
CUST GROWTH RATE= 2.28%/YR
INITIAL SYSTEM LOAD= 18.3 GW
SYSTEM LOAD GROWTH= 6.82%/YR
CHANGE TO 100% 2R METERING IN 10 YRS
ESCALATION RATE= 8.5%/YR
INTEREST RATE=12.00%/YR
NEW 1R A-BASE METER=$38.98
NEW 1R S-BASE METER=$29.65
NDW 2R METER=$160.00
CHANGE FROM 1R TO 2R METER=($20.00/CUST
SALVAGE OLD METER=($14.82-OPT),($0.00-CONV)
READING AND BILLING 1R=$12.99/YR
READING AND BILLING 2R=$15.09/YR
REPROGRAMMING COMPUTER=$400000.00
TESTING 1R METER=$18.00
TESTING 2R METER=$25.00

RESETTING CLOCK IN 2R METER=$ 2.00
PROB OF OUTAGE REQ RESET= .10/YR
STORAGE HEATER=$2500.00
STORAGE HEATING POTENTIAL=.59
CAPITAL COST OF SYSTEM CAPACITY=$802.10/KW
COST OF PEAK ENERGY=$ 1.96 CENTS/KWHR
COST OF OFF-PEAK ENERGY=$ 1.40 CENTS/KWHR
PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
DEMAND SAVING PER STORAGE HEATER= 6.3 KW
ELECTRIC HTG LOAD= 29.60 MWHR/YR
ELECTRIC HTG SATURATION=.10
ELEC HTG ELASTICITY=-0.20
AVG COINC PEAK DEMAND=2.67 KW/CUST
AVG PEAK ENERGY= 5.31 MWHR/CUST
AVG OFF-PEAK ENERGY= 4.53 MWHR/CUST
SINGLE RATE= 2.91 CENTS/KWHR
RATE DIFF = 1.00 CENTS/KWHR

CONTINUATION WITH SINGLE-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NDW 1R METERS	10985.	2164.	2384.	2626.	2894.	3190.	3516.	2731.	3030.	3363.	3732.	4142.	4596.	5120.	5660.	6281.	6978.	7735.	8554.	9526.	10572.	11752.	13019.	16862.
READING AND BILLING 1R	1285106.	28414.	31532.	34992.	38632.	43893.	47822.	53078.	58894.	65357.	72529.	80488.	89321.	99122.	112000.	122071.	134467.	150333.	166838.	185138.	207454.	228000.	253821.	280787.
CHECKING 1R METERS	12256.	0.	0.	0.	0.	0.	0.	0.	689.	765.	849.	942.	1045.	1160.	1287.	1428.	1585.	1759.	1952.	2166.	2434.	2668.	2960.	3285.
RECALIBRATING 1R METERS	46594.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	8133.	9824.	10015.	11114.	12353.	13687.	15188.	16855.	18705.
YEARLY COST	1353461.	305777.	33915.	37618.	41726.	46283.	51338.	55801.	62613.	69484.	77109.	85571.	94962.	105383.	116947.	137912.	153047.	169842.	188480.	209163.	232116.	257588.	285856.	142615.
PRESENT VALUE	1353461.	305777.	32308.	34121.	36045.	38077.	40225.	41539.	44498.	47030.	49705.	52533.	55522.	58681.	62028.	69655.	73618.	77886.	82233.	86912.	91856.	97882.	102636.	48719.

NET 1978 COST=$1353.461 MILLION

Run 7   5% discount rate

PEAK ELASTICITY=-0.30
OFF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWH?

OPTIONAL TWO-RATE METERING

TOTAL CONSERVATION=   0.485 MILLION KWH

ADDITIONAL 1978 COST=$ 37.630 MILLION
      TOTAL 1978 COST=$1391.091 MILLION
    TOTAL 1978 SAVING=$ 292.830 MILLION
    BENEFIT/COST RATIO=   7.782

NET 1978 COST=$1098.261 MILLION

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NEW 1R METERS	7477.	1745.	0.	0.	2196.	2971.	3287.	2477.	2749.	3951.	3135.	3757.	4169.	4627.	5134.	5698.	6323.	7017.	7787.	8642.	9598.	10642.	11810.	13781.
READING AND BILLING 1R	1169933.	28322.	30681.	32640.	35343.	39894.	43381.	48141.	53424.	59287.	65793.	73013.	81025.	89917.	99784.	110755.	122886.	136372.	151337.	167944.	186174.	206866.	229783.	254710.
CHECKING 1R METERS	11285.	0.	0.	0.	0.	0.	0.	0.	689.	768.	809.	860.	948.	1052.	1168.	1296.	1438.	1596.	10148.	11165.	12416.	13778.	15290.	16968.
RECALIBRATING 1R METERS	43264.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	8132.	8966.	9941.	0.	0.	0.	0.	0.	0.
REPROGRAMMING BILLING	400.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	15959.	2268.	16817.	17797.	3766.	1183.	1234.	1369.	1519.	1685.	1870.	2076.	2343.	2556.	2837.	3148.	3493.	3877.	4322.	4774.	5298.	5879.	6575.	7438.
INSTALLATION LESS SALVAGE	451.	107.	938.	225.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 2R	132165.	107.	988.	2732.	4051.	4645.	5159.	5725.	6354.	7051.	7825.	8683.	9636.	10694.	11857.	13169.	14618.	16218.	17998.	19973.	22165.	24597.	27296.	30292.
CHECKING 2R METERS	1416.	0.	0.	0.	0.	0.	0.	0.	0.	7.	56.	114.	135.	150.	165.	183.	204.	227.	252.	279.	310.	344.	382.	424.
RECALIBRATING 2R METERS	4526.	0.	0.	0.	0.	62.	68.	76.	84.	95.	104.	115.	128.	142.	157.	175.	194.	215.	239.	265.	294.	362.	402.	401.
RESETTING 2R TIMERS	1782.	19.	67.	0.	8.	721.	600.	642.	399.	218.	146.	134.	143.	158.	175.	194.	215.	239.	265.	294.	326.	362.	402.	401.
STORAGE HEATING	2412.	0.	-2.	212.	462.	62.	68.	76.	84.	95.	104.	115.	128.	142.	157.	175.	194.	215.	239.	265.	294.	326.	362.	401.
LOAD SHIFT	-9552.	0.	-2.	-12.	-32.	-83.	-172.	-292.	-416.	-330.	-522.	-703.	-784.	-871.	-967.	-1073.	-1191.	-1322.	-1467.	-1628.	-1806.	-2004.	-2224.	-5238.
CONSERVATION	-15467.	0.	-4.	-16.	-52.	-130.	-213.	-472.	-671.	-858.	-1007.	-1139.	-1270.	-1411.	-1566.	-1737.	-1928.	-2140.	-2375.	-2635.	-2924.	-3245.	-3601.	-2469.
PEAK REDUCTION	-2678111.	0.	0.	0.	0.	0.	0.	0.	-18157.	-16867.	-19157.	-21426.	-23825.	-26451.	-293556.	-325578.	-36153.	-40120.	-44523.	-49489.	-54831.	-60848.	-67525.	-74935.
YEARLY COST	1391091.	32860.	48817.	53673.	45873.	48675.	53910.	58431.	65219.	72152.	79987.	88752.	98488.	109294.	121288.	142732.	158413.	175955.	194439.	216914.	240718.	267134.	296449.	22567.
PRESENT VALUE	1391091.	32860.	45730.	48683.	39627.	40045.	42235.	43687.	40493.	48254.	51486.	55189.	59734.	58856.	64322.	72088.	76200.	86608.	85265.	90132.	100590.	106428.	106428.	7646.
YEARLY SAVING	292830.	-1.	-6.	-25.	-83.	-217.	-355.	-578.	-1778.	-12355.	-10399.	-14285.	-15131.	-16000.	-16911.	-35189.	-39272.	-43582.	-48364.	-53672.	-59562.	-66098.	-73351.	-81401.
PRESENT VALUE	-292830.	-1.	-5.	-23.	-72.	-178.	-353.	-578.	-1778.	-12355.	-10399.	-14285.	-13131.	-16000.	-16911.	-17874.	-18891.	-19965.	-21101.	-22302.	-235571.	-249912.	-26329.	-2782.
PEAK REDUCTION (MW)	3.	3.	22.	42.	48.	55.	65.	75.	85.	91.	96.	98.	101.	103.	106.	108.	110.	113.	116.	118.	121.	124.	126.	125.
% PEAK REDUCTION	0.20	0.20	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CONSERVATION (MWHS)	0.	0.	0.	0.	0.	0.	0.	15.	20.	23.	25.	26.	26.	27.	28.	28.	29.	30.	30.	31.	32.	32.	33.	33.
VALLEY PEAK	67.8	67.8	65.2	65.1	65.4	65.4	65.5	65.5	65.5	65.5	65.5	65.5	65.4	65.4	65.4	65.4	65.4	65.4	65.3	65.3	65.3	65.3	65.3	65.3
THOUS OF 1IR METERS	14.	14.	107.	201.	219.	225.	230.	235.	241.	246.	252.	257.	263.	269.	275.	282.	288.	295.	301.	328.	315.	322.	330.	337.
THOUS STORAGE HEATERS	0.	0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.

Run 7 5% discount rate

PEAK ELASTICITY=-0.30
0FF-PEAK ELASTICITY=-0.20
PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
RATE DIFF = 1.00 CENTS/KWHR

CONVERSION TO TWO-RATE METERING

	TOTAL	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	[illegible]
NDW 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 1R	153156.	26654.	25803.	24633.	23097.	21143.	18713.	15745.	12165.	7896.	2850.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHECKING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
RECALIBRATING 1R METERS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
REPROGRAMMING BILLING	400.	400.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NEW 2R METERS	140860.	43353.	47038.	51037.	55375.	60081.	65188.	70729.	76741.	83264.	90342.	22349.	24801.	27523.	30543.	33895.	37615.	41742.	46323.	51406.	57348.	63308.	70255.	-1729231.
INSTALLATION LESS SALVAGE	50143.	4420.	4774.	5156.	5569.	5987.	6466.	6983.	7541.	8135.	8752.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
READING AND BILLING 2R	1313317.	2044.	6654.	12033.	18279.	25499.	33814.	43359.	54283.	66749.	80944.	93500.	103760.	115147.	127783.	141825.	157367.	174636.	193800.	215067.	238669.	264860.	293925.	326179.
CHECKING 2R METERS	12919.	0.	0.	0.	0.	0.	0.	0.	0.	130.	282.	459.	663	902.	1174.	1486.	1842.	2249.	2711.	3009.	3339	3705.	4112.	4563.
RECALIBRATING 2R METERS	31046.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1535.	3332.	5422.	7844.	10639.	13851.	17534.	21742.
RESETTING 2R TIMERS	17426.	27.	88.	159.	242.	338.	448.	575.	719.	885.	1073.	1239.	1375.	1526.	1694.	1879.	2086.	2315.	2569.	2850.	3163.	3510.	3896.	4323.
STORAGE HEATING	1822.	2.	11.	37.	96.	190.	299.	396.	468.	522.	571.	616.	654.	665.	625.	530.	414.	330.	295.	302.	328.	362.	402.	-8171.
LOAD SHIFT	-91489.	-3.	-17.	-68.	-202.	-471.	-908.	-1510.	-2259.	-3144.	-4168.	-5339.	-6661.	-8109.	-9627.	-11148.	-12645.	-14157.	-15753.	-17492.	-19413.	-21544.	-23908.	-26532.
CONSERVATION	-148054.	-5.	-28.	-111.	-326.	-762.	-1469.	-2444.	-3656.	-5088.	-6746.	-8641.	-10779.	-13123.	-15580.	-18040.	-20463.	-22910.	-25491.	-28306.	-31415.	-34864.	-38690.	-42935.
PEAK REDUCTION	-1270025.	0.	0.	0.	0.	0.	0.	0.	0.	-49285.	-64258.	-80460.	-98720.	-118750.	-139838.	-161134.	-182328.	-203930.	-226842.	-251870.	-279537.	-310213.	-344262.	-382041.
YEARLY COST	1721070.	76901.	84369.	93056.	102657.	113238.	124930.	137787.	151918.	167552.	184813.	113163.	131256.	145763.	161819.	179595.	200859.	224603.	251121.	280479.	313185.	349597.	390123.	-1380595.
PRESENT VALUE	1721070.	76901.	80351.	84405.	88679.	93161.	97886.	102819.	107965.	113426.	119132.	72542.	76743.	81166.	85816.	90708.	96617.	102893.	109563.	116545.	123938.	131759.	140032.	-471956.
YEARLY SAVING	-1509569.	-8.	-46.	-179.	-528.	-1233.	-2377.	-3954.	-5915.	-57517.	-75172.	-94440.	-116164.	-139982.	-165045.	-190323.	-215437.	-240997.	-268087.	-297667.	-330366.	-366626.	-406860.	-451508.
PRESENT VALUE	-1509569.	-8.	-44.	-163.	-456.	-1014.	-1863.	-2951.	-4234.	-38933.	-48457.	-57978.	-67916.	-77947.	-87527.	-96126.	-103629.	-110404.	-116965.	-123687.	-130737	-138178.	-146039.	-154348.
PEAK REDUCTION (MW)		6.	13.	24.	43.	72.	113.	161.	213.	267.	320.	370.	418.	464.	503.	534.	557.	574.	589.	603.	616.	630.	645.	660.
% PEAK REDUCTION		0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.9	1.0	1.0	1.1	1.2	1.2	1.2	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9
CONSERVATION (MWHRS)		0.	1.	5.	13.	28.	50.	76.	105.	135.	165.	195.	224.	252.	275.	294.	307.	317.	325.	333.	340.	348.	356.	364.
% VALLEY/PEAK		65.1	65.1	65.2	65.3	65.4	65.6	65.8	66.0	66.1	66.3	66.4	66.4	66.5	66.5	66.5	66.5	66.4	66.4	66.3	66.2	66.2	66.1	66.1
THOUS OF IIR METERS		271.	542.	813.	1084.	1355.	1626.	1897.	2168.	2439.	2710.	2771.	2835	2899.	2965.	3033.	3102.	3173.	3245.	3319.	3392.	3472.	3551.	3632.
THOUS STORAGE HEATERS		0.	0.	0.	0.	0.	0.	0.	0.	0.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.	1.

TOTAL CONSERVATION= 4.509 MILLION KWH

ADDITIONAL 1978 COST=$ 367.609 MILLION
TOTAL 1978 COST=$1721.070 MILLION
TOTAL 1978 SAVING=$1509.569 MILLION
BENDFIT/COST RATIO= 4.106

NDT 1978 COST=$ 211.501 MILLION

SENSITIVITY ANALYSIS? YES

       INITIAL NUMBER OF CUSTOMERS=2212.THOUSAND
SENSITIVITY: IR= 0.994   OPT IIR= 0.993   IIR= 1.000

       CUST GROWTH RATE= 2.28%/YR
SENSITIVITY: IR= 0.246   OPT IIR= 0.246   IIR= 0.232

       INITIAL SYSTEM LOAD= 18.3 GW
SENSITIVITY: IR= 0.000   OPT IIR= 0.000   IIR= 0.000

       SYSTEM LOAD GROWTH= 6.8%/YR
SENSITIVITY: IR= 0.000   OPT IIR= 0.000   IIR= 0.000

       CHANGE TO 100% 2R METERING IN 10 YRS
SENSITIVITY: IR= 0.000   OPT IIR= 0.000   IIR=-0.001

       ESCALATION RATE= 8.5%/YR
SENSITIVITY: IR= 0.866   OPT IIR= 0.863   IIR= 0.188

       INTEREST RATE=12.00%/YR
SENSITIVITY: IR=-1.035   OPT IIR=-1.026   IIR=-0.684

       NEW 1R A-BASE METER=$38.98
SENSITIVITY: IR= 0.006   OPT IIR= 0.006   IIR= 0.000

       NEW 1R S-BASE METER=$29.65
SENSITIVITY: IR= 0.025   OPT IIR= 0.021   IIR= 0.000

       NEW 2R METER=$160.00
SENSITIVITY: IR= 0.000   OPT IIR= 0.010   IIR= 0.475

       CHANGE FROM 1R TO 2R METER=$20.00/CUST
SENSITIVITY: IR= 0.000   OPT IIR= 0.002   IIR= 0.056

       SALVAGE OLD METER=($14.82-OPT),($0.00-CONV)
SENSITIVITY: IR= 0.000   OPT IIR= 0.000   IIR= 0.000

       READING AND BILLING 1R=$12.99/YR
SENSITIVITY: IR= 0.938   OPT IIR= 0.914   IIR= 0.191

       READING AND BILLING 2R=$15.09/YR
SENSITIVITY: IR= 0.000   OPT IIR= 0.009   IIR= 0.810

       REPROGRAMMING COMPUTER=$400000.00
SENSITIVITY: IR= 0.000   OPT IIR= 0.001   IIR= 0.001

       TESTING 1R METER=$18.00
SENSITIVITY: IR= 0.030   OPT IIR= 0.030   IIR= 0.000

```
        TESTING 2R METER=$25.00
SENSITIVITY:   IR= 0.000   OPT IIR= 0.002   IIR= 0.020

        RESETTING CLOCK IN 2R METER=$ 2.00
SENSITIVITY:   IR= 0.000   OPT IIR= 0.000   IIR= 0.011

        PROB OF OUTAGE REQ RESET= .10/YR
SENSITIVITY:   IR= 0.000   OPT IIR= 0.000   IIR= 0.011

        STORAGE HEATER=$2500.00
SENSITIVITY:   IR= 0.000   OPT IIR= 0.001   IIR= 0.001

        STORAGE HEATING POTENTIAL=.59
SENSITIVITY:   IR= 0.000   OPT IIR=-0.000   IIR=-0.000

        CAPITAL COST OF SYSTEM CAPACITY=$802.10/KW
SENSITIVITY:   IR= 0.000   OPT IIR=-0.003   IIR=-0.471

        COST OF PEAK ENERGY=$ 1.96 CENTS/KWHR
SENSITIVITY:   IR= 0.000   OPT IIR=-0.001   IIR=-0.182

        COST OF OFF-PEAK ENERGY=$ 1.40 CENTS/KWHR
SENSITIVITY:   IR= 0.000   OPT IIR= 0.000   IIR= 0.089

        PEAK ELASTICITY=-0.30
SENSITIVITY:   IR= 0.000   OPT IIR=-0.001   IIR=-0.428

        OFF-PEAK ELASTICITY=-0.20
SENSITIVITY:   IR= 0.000   OPT IIR= 0.000   IIR= 0.062

        PEAK/OFF-PEAK CROSS ELASTICITY= 0.10
SENSITIVITY:   IR= 0.000   OPT IIR=-0.000   IIR=-0.140

        DEMAND SAVING PER STORAGE HEATER= 6.3 KW
SENSITIVITY:   IR= 0.000   OPT IIR=-0.002   IIR=-0.058

        ELECTRIC HTG LOAD= 29.60 MWHR/YR
SENSITIVITY:   IR= 0.000   OPT IIR=-0.050   IIR=-0.002

        ELECTRIC HTG SATURATION=.10
SENSITIVITY:   IR= 0.000   OPT IIR=-0.001   IIR=-0.058

        ELEC HTG ELASTICITY=-0.20
SENSITIVITY:   IR= 0.000   OPT IIR=-0.001   IIR=-0.058

        AVG COINC PEAK DEMAND=2.67 KW/CUST
SENSITIVITY:   IR= 0.000   OPT IIR=-0.001   IIR=-0.412

        AVG PEAK ENERGY=  5.31 MWHR/CUST
SENSITIVITY:   IR= 0.000   OPT IIR=-0.342   IIR= 0.012

        AVG OFF-PEAK ENERGY= 4.53 MWHR/CUST
SENSITIVITY:   IR= 0.000   OPT IIR= 0.013   IIR=-0.103

        SINGLE RATE= 2.91 CENTS/KWHR
SENSITIVITY:   IR= 0.000   OPT IIR= 0.002   IIR= 0.512

        RATE DIFF = 0.70 CENTS/KWHR
SENSITIVITY:   IR= 0.000   OPT IIR=-0.062   IIR=-0.566
```

READING AND BILLING COSTS 1974

	Single-Rate	Est. Two-Rate

Reading:

73¢ x 3,034,000 = 2,214,800 x 110% = 2,436,300

Area Clerical:

- Check: 3¢ x 3,034,000 =   91,000 x 150% =   136,500

- Entering .18 std min @
  $16.40/eff hr
          5¢ x 3,034,000 =   149,300 x 150% =   224,000

Computing:

- Maintenance:
          373,500 x 36.4% =   136,000   =   136,000

- Data Validation:
          1,242,000 x 36.4% =   452,100 x 150% =   678,200

- Running:
          1,781,333 x 36.4% =   648,400 x 150% =   972,600

- Terminals & Lines: =   284,000   =   284,000

Readjustments:
          $12 x 36,860 =   442,300 x 150% =   663,500

Bills: 0.4¢ x 5,500,000 =   22,000   =   22,000

Envelopes:
          2.7¢ x 5,500,000 =   148,500   =   148,500

Postage: 8¢ x 5,500,000 =   440,000   =   440,000

	Single-Rate	Est. Two-Rate

Mailing Clerical:

- Folding:
$\dfrac{\$12.05/hr}{10,000/hr}$ = .12¢x5,500,000 =   6,600   =   6,600

- Inserting:
$\dfrac{\$25.95/hr}{6,000/hr}$ = .43¢x5,500,000 =   23,800   =   23,800

-Decollating & Bursting:
    .5¢ x 5,500,000 =   27,500   =   27,500

Collecting Clerical:
    .78 std min @
  $16.40/eff hr
   = 21¢ x 4,500,000 = 945,000   = 945,000

Banking:

    20¢ x 4,500,000 = 900,000   = 900,000

Total Annual Cost   6,931,300   8,044,500

Annual Cost per
Customer ÷ 742,000   = $9.34 $10.84

                  x 1.39*   x 1.39*

1978 Cost   = $12.99 $15.09

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*
	%			%	
CPI 1971 - 100.0		108.7%	CPI 1975 - 100.0		125.6%
1974 - 125.0			1978 - 125.6		
1975 - 138.5					

        108.7% x 125.6% = 139.2%

K. ANNEX D

ONTARIO HYDRO MARGINAL CAPITAL COST OF CAPACITY EXCLUDING O & M AND LOSSES

	1975 (100%)	1978 (135.5%)[1]
Bulk Capacity Cost	$377.13/kW[2]	$511.01/kW
T1	$46.57/kW[3]	$63.10/kW
T2	$73.43/kW[3]	$99.50/kW
Non-Common Distribution	$13.05/kW[3]	$17.70/kW
Retail Distribution	$81.76/kW[3]	$110.79/kW
Total	$591.94/kW	$802.10/kW

1 OCE for coal fired stations

2 Bulk Power Marginal Cost Study

3 Derived from information prepared for Marginal Cost Study

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TY TOD6
      REAL RPG,IRA,IRS,IIR,SAL,SALV,STH,CRPG(30),INT,ESC,NC(30),STHF,SW
      REAL MCG,CLDSH(30),CONS(5),RDIF,SRATE,XF,HTGLD,TVIR,TVIIR,CT(5)
      REAL TVSTH,CIIRM,SIIRM,MF,CEL,CCON(30),PEN,OPEN,BT(5),AC(5),CON
      REAL IIRMF,QXM,XM,PXM(30),UNIIR(30),CIII,EHFT,EHEL,NELH(30),DEFL
      REAL CIR(30),CIIR(30),CSTH(30),ARPG(30),KW,CIN(30),C(5),BCR(5)
      REAL AIR(30),AIIR(30),CRES(30),ANF,PVC(30),CII,PVR(30),YRBT
      REAL SKW,RAB,CRBI(30),CRBII(30),CHKI(30),CHKII(30),RBI,RBII,SFI
      REAL RES,PRB,TSTI,TSTII,MI,MII,CRC1(30),CRCII(30),CSKW(30),RDN(30)
      REAL NIR(30),NIIR(30),ESCF,ANNF,NNIR,NNIIR,YRC(30),YRCT,INST,CI
      REAL NSTH(30),NNSTH,CHDLD(30),CHNLD(30),RDEM(30),UCDLD(30),SFII
      REAL UCNLD(30),DKW,DMWH,NMWH,STEL,DEL,NEL,DRAT,DDEM,YRB(30)
      REAL NRAT,SRAT,UCDDM(30),UCNDM(30),UNSTH(30),RLD(30),NRDEM,NDEM
      REAL DEM(30),DGR,CHDDM(30),CHNDM(30),VALF(30),X,QX,PX(30),GR
      INTEGER NY,NYC,Q,QS,I,J,K,YI,YII,YN(30)
      QS=0
    1 FORMAT (10X,'BASIC ASSUMPTIONS:')
      TYPE 1
    3 FORMAT (10X,'STUDY PERIOD=',I4,' TO ',I4)
      YI=1978
      YII=2000
      TYPE 3,YI,YII
    5 FORMAT (10X,'INITIAL NUMBER OF CUSTOMERS=',F5.0,'THOUSAND')
      NC(1)=2212
      TYPE 5,NC(1)
    7 FORMAT (10X,'CUST GROWTH RATE=',F5.2,'%/YR')
      GR=2.28
      TYPE 7,GR
    2 FORMAT (10X,'INITIAL SYSTEM LOAD=',F5.1,' GW')
      DEM(1)=18.3
      TYPE 2,DEM(1)
    4 FORMAT (10X,'SYSTEM LOAD GROWTH=',F4.1,'%/YR')
      DGR=6.77
      TYPE 4,DGR
    9 FORMAT (10X,'CHANGE TO 100% 2R METERING IN ',I2,' YRS')
      NYC=10
      TYPE 9,NYC
   11 FORMAT (10X,'ESCALATION RATE=',F4.1,'%/YR')
      ESC=8.5
      TYPE 11,ESC
   13 FORMAT (10X,'INTEREST RATE=',F5.2,'%/YR')
      INT=12
      TYPE 13,INT
   15 FORMAT (10X,'NEW 1R A-BASE METER=$',F5.2)
      IRA=44.46
      TYPE 15,IRA
   16 FORMAT (10X,'NEW 1R S-BASE METER=$',F5.2)
      IRS=33.85
      TYPE 16,IRS
   17 FORMAT (10X,'NEW 2R METER=$',F6.2)
      IIR=150.72
      TYPE 17,IIR
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19 FORMAT (10X,'CHANGE FROM 1R TO 2R METER=$',F5.2,'/CUST')
   INST=20
   TYPE 19,INST
20 FORMAT (10X,'SALVAGE OLD METER=($',F5.2,'-OPT),($0.00-CONV)')
   SALV=IRS/2
   TYPE 20,SALV
21 FORMAT (10X,'READING AND BILLING 1R=$',F5.2,'/YR')
   RBI=12.99
   TYPE 21,RBI
23 FORMAT (10X,'READING AND BILLING 2R=$',F5.2,'/YR')
   RBII=15.09
   TYPE 23,RBII
25 FORMAT (10X,'REPROGRAMMING COMPUTER=$',F9.2)
   RPG=400000
   TYPE 25,RPG
27 FORMAT (10X,'TESTING 1R METER=$',F5.2)
   TSTI=25.05
   TYPE 27,TSTI
29 FORMAT (10X,'TESTING 2R METER=$',F5.2)
   TSTII=34.79
   TYPE 29,TSTII
   IF (Q.EQ.5) GO TO 160
31 FORMAT (10X,'RESETTING CLOCK IN 2R METER=$',F5.2)
   RES=2.00
   TYPE 31,RES
33 FORMAT (10X,'PROB OF OUTAGE REQ RESET=',F4.2,'/YR')
   PRB=.1
   TYPE 33,PRB
35 FORMAT (10X,'STORAGE HEATER=$',F7.2)
   STH=2500
   TYPE 35,STH
36 FORMAT (10X,'STORAGE HEATING POTENTIAL=',F3.2)
   STEL=.59
   TYPE 36,STEL
37 FORMAT (10X,'CAPITAL COST OF SYSTEM CAPACITY=$',F6.2,'/KW')
   KW=746.70
   TYPE 37,KW
38 FORMAT (10X,'COST OF PEAK ENERGY=$',F5.2,' CENTS/KWHR')
   PEN=1.96
   TYPE 38,PEN
43 FORMAT (10X,'COST OF OFF-PEAK ENERGY=$',F5.2,' CENTS/KWHR')
   OPEN=1.40
   TYPE 43,OPEN
47 FORMAT (10X,'PEAK ELASTICITY=',F5.2)
   DEL=-.3
   TYPE 47,DEL
48 FORMAT (10X,'OFF-PEAK ELASTICITY=',F5.2)
   NEL=-.2
   TYPE 48,NEL
49 FORMAT (10X,'PEAK/OFF-PEAK CROSS ELASTICITY=',F5.2)
   CEL=0.1
   TYPE 49,CEL
39 FORMAT (10X,'DEMAND SAVING PER STORAGE HEATER=',F4.1,' KW')
   SKW=6.3
   TYPE 39,SKW
40 FORMAT (10X,'ELECTRIC HTG LOAD=',F6.2,' MWHR/YR')
   HTGLD=29.6
   TYPE 40,HTGLD
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54  FORMAT (10X,'ELECTRIC HTG SATURATION=',F3.2)
    EHFT=.1
    TYPE 54,EHFT
55  FORMAT (10X,'ELEC HTG ELASTICITY=',F5.2)
    EHEL=-.2
    TYPE 55,EHEL
51  FORMAT (10X,'AVG COINC PEAK DEMAND=',F4.2,' KW/CUST')
    DKW=2.67
    TYPE 51,DKW
52  FORMAT (10X,'AVG PEAK ENERGY=',F6.2,' MWHR/CUST')
    DMWH=5.31
    TYPE 52,DMWH
53  FORMAT (10X,'AVG OFF-PEAK ENERGY=',F5.2,' MWHR/CUST')
    NMWH=4.53
    TYPE 53,NMWH
41  FORMAT (10X,'SINGLE RATE=',F5.2,' CENTS/KWHR')
    SRATE=2.91
    TYPE 41,SRATE
42  FORMAT (10X,'RATE DIFF =',F5.2,' CENTS/KWHR')
    RDIF=.7
    TYPE 42,RDIF
    IF (Q.NE.5) GO TO 45
    TYPE 155
    GO TO 1
45  NY=YII-YI+1
    NIR(0)=NC(1)/(1+GR/100)
    NIIR(0)=0
    VALF(0)=65
    DO 150 Q=1,3
    CIR(0)=0
    CRBI(0)=0
    CHKI(0)=0
    CRCI(0)=0
    CRPG(0)=0
    CIIR(0)=0
    CIN(0)=0
    CRBII(0)=0
    CHKII(0)=0
    CRCII(0)=0
    CRES(0)=0
    CSTH(0)=0
    CLDSH(0)=0
    CCON(0)=0
    CSKW(0)=0
    YRC(0)=0
    PVC(0)=0
    YRB(0)=0
    PVB(0)=0
    TVIR=0
    TVIIR=0
    TVSTH=0
    CON=0
    YRCT=0
    YRBT=0
    YOHT=0
    YCUT=0
    DO 50 I=0,NY
    CHDLD(I)=0
```

```
      CHNLD(I)=0
      CHDDM(I)=0
      CHNDM(I)=0
      NSTH(I)=0
50    YN(I)=YI+I-1
      ANNF=INT/100/((1+INT/100)**30-1)+INT/100
      DO 100 I=1,NY
      NC(I+1)=NC(I)*(1+GR/100)
      DEM(I+1)=DEM(I)*(1+DGR/100)
      ESCF=(1+ESC/100)**(I-1)
      DEFL=1/(1+INT/100)**(I-1)
      SRAT=SRATE*ESCF
      DRAT=RDIF*ESCF/(1+DMWH/NMWH)+SRAT
      NRAT=SRAT-DMWH/NMWH*(DRAT-SRAT)
      IF (I.EQ.1) CRPG(I)=RPG/1000
      NIIR(I)=I/NYC*NC(NYC)
      IF (I.GT.NYC) NIIR(I)=NC(I)
      IF (Q.NE.2) GO TO 59
      CIIRM=(ANNF*(IIR-IRS+INST)+RBII-RBI+.0766*(TSTII)+PRB*RES)*ESCF
      SIIRM=HTGLD*10*(SRAT-(.45*DRAT+.55*NRAT))
      MF=EXP(10*(SIIRM-CIIRM)/CIIRM)
      IIRMF=EHFT*((MF-1/MF)/(MF+1/MF)+1)/2
      UNIIR(I)=IIRMF*NC(I)
      XM=ABS(1.5*(I-2))
      QXM=.5/(1+.196854*XM+.115194*XM*XM+.000344*XM*XM*XM+
     +.019527*XM*XM*XM*XM)**4
      PXM(I)=1-QXM
      IF (I.LT.2) PXM(I)=QXM
      NIIR(I)=0
      DO 58 J=1,I
58    NIIR(I)=NIIR(I)+PXM(I-J+1)*(UNIIR(J)-UNIIR(J-1))
59    IF (Q.EQ.1) NIIR(I)=0
      NIR(I)=NC(I)-NIIR(I)
      CRBI(I)=(NIR(I)+NIR(I-1))/2*RBI*ESCF
      CRBII(I)=(NIIR(I)+NIIR(I-1))/2*RBII*ESCF
      CRES(I)=PRB*(NIIR(I)+NIIR(I-1))/2*RES*ESCF
      IF (I.LT.8) GO TO 60
      CHKI(I)=.01*NIR(I-8)*TSTI*ESCF
      CHKII(I)=.01*NIIR(I-8)*TSTII*ESCF
      IF (I.LT.15) GO TO 70
      CRCI(I)=1/15*NIR(I-15)*TSTI*ESCF
      CRCII(I)=1/15*NIIR(I-15)*TSTII*ESCF
      GO TO 80
60    CHKI(I)=.01*NIR(0)*(NC(0)/NC(1))**(8-I)*TSTI*ESCF
      CHKII(I)=0
70    CRCI(I)=1/15*NIR(0)*(NC(0)/NC(1))**(15-I)*TSTI*ESCF
      CRCII(I)=0
80    NNIR=NIR(I)-NIR(I-1)
      NSAL=0
      IF (NNIR.GT.0) GO TO 90
      NSAL=-NNIR
      NNIR=0
      CHKI(I)=0
      CRCI(I)=0
90    NNIIR=NIIR(I)-NIIR(I-1)
      CIR(I)=NNIR*IRS*ESCF
      IF (I.LE.6) CIR(I)=CIR(I)+18*IRA*ESCF
      IF (NNIR.EQ.0) CIR(I)=0
```

```
      TVIR=TVIR+NNIR*(30-NY+I)/30
      CIIR(I)=NNIIR*IIR*ESCF
      TVIIR=TVIIR+NNIIR*(30-NY+I)/30
      IF (I.LT.NY) GO TO 95
      CIR(I)=CIR(I)-TVIR*IRS*ESCF
      CIIR(I)=CIIR(I)-TVIIR*IIR*ESCF
   95 SAL=SALV
      IF (Q.EQ.3) SAL=0
      CIN(I)=NSAL*(INST-SAL)*ESCF
      UCDLD(I)=DMWH*1000*(DEL*(DRAT-SRAT)/SRAT+
     +CEL*(NRAT-SRAT)/SRAT)*NIIR(I)
      UCNLD(I)=NMWH*1000*(NEL*(NRAT-SRAT)/SRAT+
     +CEL*(DRAT-SRAT)/SRAT)*NIIR(I)
      UCDDM(I)=DKW*(DEL*(DRAT-SRAT)/SRAT+
     +CEL*(NRAT-SRAT)/SRAT)*NIIR(I)
      UCNDM(I)=.65*DKW*(NEL*(NRAT-SRAT)/SRAT+
     +CEL*(DRAT-SRAT)/SRAT)*NIIR(I)
      XF=EXP(10*(HTGLD*10*((16*DRAT+8*NRAT)/24
     +-NRAT)-ANNF*STH*ESCF)/(ANNF*STH*ESCF))
      STHF=STEL*((XF-1/XF)/(XF+1/XF)+1)/2
      UNSTH(I)=STHF*NIIR(I)
      IF (Q.EQ.2) UNSTH(I)=STHF*NC(I)
      X=ABS(.6*(I-5))
      QX=.5/(1+.196854*X+.115194*X*X+.000344*X*X*X+
     +.019527*X*X*X*X)**4
      PX(I)=1-QX
      IF (I.LT.5) PX(I)=QX
      DO 93 J=1,I
      CHDLD(I)=CHDLD(I)+PX(I-J+1)*(UCDLD(J)-UCDLD(J-1))
      CHNLD(I)=CHNLD(I)+PX(I-J+1)*(UCNLD(J)-UCNLD(J-1))
      CHDDM(I)=CHDDM(I)+PX(I-J+1)*(UCDDM(J)-UCDDM(J-1))
      CHNDM(I)=CHNDM(I)+PX(I-J+1)*(UCNDM(J)-UCNDM(J-1))
   93 NSTH(I)=NSTH(I)+PX(I-J+1)*(UNSTH(J)-UNSTH(J-1))
      NELH(I)=EHFT*NIIR(I)
      IF (Q.EQ.2) NELH(I)=NIIR(I)
      CHDLD(I)=CHDLD(I)+NELH(I)*16*HTGLD/24*EHEL*
     +(DRAT-SRAT)/SRAT
      CHNLD(I)=CHNLD(I)+NELH(I)*8*HTGLD/24*EHEL*
     +(NRAT-SRAT)/SRAT
      CHDDM(I)=CHDDM(I)+NELH(I)*SKW*EHEL*(DRAT-SRAT)/SRAT
      CHNDM(I)=CHNDM(I)+NELH(I)*SKW*EHEL*(NRAT-SRAT)/SRAT
      RLD(I)=-(CHDLD(I)+CHNLD(I))/1000
      CLDSH(I)=(CHNLD(I)+16/24*HTGLD*NSTH(I))*
     +(OPEN-PEN)/100*ESCF
      CCON(I)=(CHDLD(I)+CHNLD(I))*PEN/100*ESCF
      CON=CON+RLD(I)/1000
      DDEM=1000*DEM(I)+CHDDM(I)-NSTH(I)*SKW
      NDEM=650*DEM(I)+CHNDM(I)+NSTH(I)*3*SKW
      VALF(I)=NDEM/DDEM*100
      RDEM(I)=NSTH(I)*SKW-CHDDM(I)
      IF (VALF(I).LE.100) GO TO 94
      RDEM(I)=350*DEM(I)-(CHNDM(I)+NSTH(I)*3*SKW)
   94 RDN(I)=RDEM(I)/DEM(I)/10
      NNSTH=NSTH(I)-NSTH(I-1)
      CSTH(I)=NNSTH*STH*ESCF
      TVSTH=TVSTH+NNSTH*(20-NY+I)/20
      IF (I.EQ.NY) CSTH(I)=CSTH(I)-TVSTH*STH*ESCF
      CSKW(I)=-INT/100*RDEM(I)*KW*ESCF
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```
      IF (1.LE.8) CSKW(I)=0
      YRC(1)=CIR(I)+CRBI(I)+CHKI(I)+CRCI(I)
      IF (Q.EQ.1) GO TO 97
      YRC(I)=YRC(I)+CRPG(1)+C1IR(1)+CIN(1)+CRBII(I)+CHKII(1)+
     +CRCII(I)+CRES(I)+CSTH(I)
      YRB(I)=CLDSH(I)+CCON(I)+CSKW(I)
      PVB(I)=YRB(I)*DEFL
      YRBT=YRBT+PVB(I)
   97 PVC(1)=YRC(1)*DEFL
      YRCT=YRCT+PVC(I)
      CIR(0)=CIR(0)+C1R(I)*DEFL
      CRBI(0)=CRBI(0)+CRBI(I)*DEFL
      CHKI(0)=CHKI(0)+CHKI(I)*DEFL
      CRCI(0)=CRCI(0)+CRCI(I)*DEFL
      CRPG(0)=CRPG(0)+CRPG(I)*DEFL
      C1IR(0)=C11R(0)+C11R(1)*DEFL
      CIN(0)=CIN(0)+CIN(1)*DEFL
      CRBII(0)=CRBII(0)+CRBII(I)*DEFL
      CHKII(0)=CHKII(0)+CHKII(I)*DEFL
      CRCII(0)=CRCII(0)+CRCII(I)*DEFL
      CRES(0)=CRES(0)+CRES(I)*DEFL
      CSTH(0)=CSTH(0)+CSTH(I)*DEFL
      CLDSH(0)=CLDSH(0)+CLDSH(I)*DEFL
      CCON(0)=CCON(0)+CCON(I)*DEFL
      CSKW(0)=CSKW(0)+CSKW(I)*DEFL
      YRC(0)=YRC(0)+YRC(I)*DEFL
      PVC(0)=PVC(0)+PVC(I)
      YRB(0)=YRB(0)+YRB(I)*DEFL
      PVB(0)=PVB(0)+PVB(I)
  100 CONTINUE
      C(Q)=YRCT/1000
      IF (Q.EQ.1) GO TO 101
      CONS(Q)=CON
      CT(Q)=C(Q)
      BT(Q)=-(YRBT/1000)
      C(Q)=CT(Q)-BT(Q)
      AC(Q)=CT(Q)-C(1)
      BCR(Q)=BT(Q)/AC(Q)
  101 IF (QS.NE.0) GO TO 150
  104 FORMAT (///20X,'CONTINUATION WITH SINGLE-RATE METERING'//)
      IF (Q.EQ.1) TYPE 104
  105 FORMAT (///30X,'OPTIONAL TWO-RATE METERING'//)
      IF (Q.EQ.2) TYPE 105
  106 FORMAT (///25X,'CONVERSION TO TWO-RATE METERING'//)
      IF (Q.EQ.3) TYPE 106
  108 FORMAT (29X,'TOTAL',4I9/)
      TYPE 108,(YN(I),I=1,4)
  110 FORMAT (1X,'        NEW 1R METERS       ',5F9.0)
      TYPE 110,(CIR(I),I=0,4)
  112 FORMAT (1X,' READING AND BILLING 1R ',5F9.0)
      TYPE 112,(CRBI(I),I=0,4)
  114 FORMAT (1X,'   CHECKING 1R METERS     ',5F9.0)
      TYPE 114,(CHKI(I),I=0,4)
  116 FORMAT (1X,' RECALIBRATING 1R METERS ',5F9.0)
      TYPE 116,(CRCI(I),I=0,4)
      IF (Q.EQ.1) GO TO 134
  118 FORMAT (1X,'  REPROGRAMMING BILLING  ',5F9.0)
      TYPE 118,(CRPG(I),I=0,4)
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120 FORMAT (1X,'        NEW 2R METERS        ',5F9.0)
    TYPE 120,(CIIR(I),I=0,4)
121 FORMAT (1X,'INSTALLATION LESS SALVAGE',5F9.0)
    TYPE 121,(CIN(I),I=0,4)
122 FORMAT (1X,' READING AND BILLING 2R  ',5F9.0)
    TYPE 122,(CRBII(I),I=0,4)
124 FORMAT (1X,'   CHECKING 2R METERS    ',5F9.0)
    TYPE 124,(CHKII(I),I=0,4)
126 FORMAT (1X,' RECALIBRATING 2R METERS ',5F9.0)
    TYPE 126,(CRCII(I),I=0,4)
128 FORMAT (1X,'   RESETTING 2R TIMERS   ',5F9.0)
    TYPE 128,(CRES(I),I=0,4)
130 FORMAT (1X,'      STORAGE HEATING    ',5F9.0)
    TYPE 130,(CSTH(I),I=0,4)
144 FORMAT (1X,'        LOAD SHIFT       ',5F9.0)
    TYPE 144,(CLDSH(I),I=0,4)
146 FORMAT (1X,'       CONSERVATION      ',5F9.0)
    TYPE 146,(CCON(I),I=0,4)
132 FORMAT (1X,'       PEAK REDUCTION    ',5F9.0)
    TYPE 132,(CSKW(I),I=0,4)
134 FORMAT (/1X,'       YEARLY COST       ',5F9.0)
    TYPE 134,(YRC(I),I=0,4)
135 FORMAT (1X,'       PRESENT VALUE      ',5F9.0)
    TYPE 135,(PVC(I),I=0,4)
    IF (Q.EQ.1) GO TO 137
125 FORMAT (1X,'       YEARLY SAVING      ',5F9.0)
    TYPE 125,(YRB(I),I=0,4)
    TYPE 135,(PVB(I),I=0,4)
129 FORMAT (/1X,'   PEAK REDUCTION (MW)   ',9X,4F9.0)
    TYPE 129,(RDEM(I),I=1,4)
127 FORMAT (1X,'    % PEAK REDUCTION      ',9X,4F9.1)
    TYPE 127,(RDN(I),I=1,4)
136 FORMAT (1X,'   CONSERVATION (MWHRS)  ',9X,4F9.0)
    TYPE 136,(RLD(I),I=1,4)
133 FORMAT (1X,'      % VALLEY/PEAK       ',9X,4F9.1)
    TYPE 133,(VALF(I),I=1,4)
139 FORMAT (1X,'    THOUS OF IIR METERS   ',9X,4F9.0)
    TYPE 139,(NIIR(I),I=1,4)
131 FORMAT (1X,'   THOUS STORAGE HEATERS  ',9X,4F9.0)
    TYPE 131,(NSTH(I),I=1,4)
143 FORMAT (/28X,'TOTAL CONSERVATION=',F9.3,' MILLION KWH')
    TYPE 143,CONS(Q)
161 FORMAT (/26X,'ADDITIONAL ',I4,' COST=$',F8.3,' MILLION')
    TYPE 161,YI,AC(Q)
163 FORMAT (31X,'TOTAL ',I4,' COST=$',F8.3,' MILLION')
    TYPE 163,YI,CT(Q)
147 FORMAT (28X,' TOTAL ',I4,' SAVING=$',F8.3,' MILLION')
    TYPE 147,YI,BT(Q)
165 FORMAT (28X,'BENEFIT/COST RATIO=',F8.3)
    TYPE 165,BCR(Q)
137 FORMAT (/32X,' NET ',I4,' COST=$',F8.3,' MILLION')
    TYPE 137,YI,C(Q)
138 FORMAT (//1X,I8,7I9/)
140 FORMAT (1X,8F9.0)
141 FORMAT (/1X,8F9.0)
142 FORMAT (1X,8F9.1)
    DO 149 J=5,NY,8
    K=J+7
```

```
      TYPE 138,(YN(I),I=J,K)
      TYPE 140,(CIR(I),I=J,K)
      TYPE 140,(CRBI(I),I=J,K)
      TYPE 140,(CHKI(I),I=J,K)
      TYPE 140,(CRCI(I),I=J,K)
      IF (Q.EQ.1) GO TO 145
      TYPE 140,(CRPG(I),I=J,K)
      TYPE 140,(CIIR(I),I=J,K)
      TYPE 140,(CIN(I),I=J,K)
      TYPE 140,(CRBII(I),I=J,K)
      TYPE 140,(CHKII(I),I=J,K)
      TYPE 140,(CRCII(I),I=J,K)
      TYPE 140,(CRES(I),I=J,K)
      TYPE 140,(CSTH(I),I=J,K)
      TYPE 140,(CLDSH(I),I=J,K)
      TYPE 140,(CCON(I),I=J,K)
      TYPE 140,(CSKW(I),I=J,K)
145   TYPE 141,(YFC(I),I=J,K)
      TYPE 140,(PVC(I),I=J,K)
      IF (Q.EQ.1) GO TO 149
      TYPE 140,(YRB(I),I=J,K)
      TYPE 140,(PVB(I),I=J,K)
      TYPE 141,(RDEM(I),I=J,K)
      TYPE 142,(RDN(I),I=J,K)
      TYPE 140,(RLD(I),I=J,K)
      TYPE 142,(VALF(I),I=J,K)
      TYPE 140,(NIIR(I),I=J,K)
      TYPE 140,(NSTH(I),I=J,K)
149   CONTINUE
150   CONTINUE
      IF (QS.NE.0) GO TO 200
      CI=C(1)
      CII=C(2)
      CIII=C(3)
151   FORMAT (///1X,'    SENSITIVITY ANALYSIS? '$)
      TYPE 151
152   FORMAT (A5)
      ACCEPT 152,ANS
      IF (ANS.NE.'YES') GO TO 154
      QS=1
      GO TO 201
200   FORMAT(5X,'SENSITIVITY:   IR=',F6.3,
     +'   OPT IIR=',F6.3,'   IIR=',F6.3/)
      SFI=(C(1)-CI)/CI*10
      IF (QS.EQ.5) SFI=SFI/10
      SFII=(C(2)-CII)/CII*10
      IF (QS.EQ.5) SFII=SFII/10
      SFIII=(C(3)-CIII)/CIII*10
      IF (QS.EQ.5) SFIII=SFIII/10
      TYPE 200,SFI,SFII,SFIII
      QS=QS+1
201   GO TO (205,207,202,204,209,211,213,215,216,217),QS
      GO TO (219,220,221,223,225,227,229,231,233,235),(QS-10)
      GO TO (236,237,238,246,247,244,239,245,251,252),(QS-20)
      GO TO (254,255,240,253,241,242,243),(QS-30)
      GO TO 154
205   TYPE 5,NC(1)
```

```
      NC(1)=NC(1)*1.1
      GO TO 45
207  NC(1)=NC(1)/1.1
      TYPE 7,GR
      GR=GR*1.1
      GO TO 45
202  GR=GR/1.1
      TYPE 2,DEM(1)
      DEM(1)=DEM(1)*1.1
      GO TO 45
204  DEM(1)=DEM(1)/1.1
      TYPE 4,DGR
      DGR=DGR*1.1
      GO TO 45
209  DGR=DGR/1.1
      TYPE 9,NYC
      NYC=NYC+1
      GO TO 45
211  NYC=NYC-1
      TYPE 11,ESC
      ESC=ESC*1.1
      GO TO 45
213  ESC=ESC/1.1
      TYPE 13,INT
      INT=INT*1.1
      GO TO 45
215  INT=INT/1.1
      TYPE 15,IRA
      IRA=IRA*1.1
      GO TO 45
216  IRA=IRA/1.1
      TYPE 16,IRS
      IRS=IRS*1.1
      GO TO 45
217  IRS=IRS/1.1
      TYPE 17,IIR
      IIR=IIR*1.1
      GO TO 45
219  IIR=IIR/1.1
      TYPE 19,INST
      INST=INST*1.1
      GO TO 45
220  INST=INST/1.1
      TYPE 20,SALV
      SALV=SALV*1.1
      GO TO 45
221  SALV=SALV/1.1
      TYPE 21,RBI
      RBI=RBI*1.1
      GO TO 45
223  RBI=RBI/1.1
      TYPE 23,RBII
      RBII=RBII*1.1
      GO TO 45
225  RBII=RBII/1.1
      TYPE 25,RPG
      RPG=RPG*1.1
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      GO TO 45
227 RPG=RPG/1.1
      TYPE 27,TSTI
      TSTI=TSTI*1.1
      GO TO 45
229 TSTI=TSTI/1.1
      TYPE 29,TSTII
      TSTII=TSTII*1.1
      GO TO 45
231 TSTII=TSTII/1.1
      TYPE 31,RES
      RES=RES*1.1
      GO TO 45
233 RES=RES/1.1
      TYPE 33,PRB
      PRB=PRB*1.1
      GO TO 45
235 PRB=PRB/1.1
      TYPE 35,STH
      STH=STH*1.1
      GO TO 45
236 STH=STH/1.1
      TYPE 36,STEL
      STEL=STEL*1.1
      GO TO 45
237 STEL=STEL/1.1
      TYPE 37,KW
      KW=KW*1.1
      GO TO 45
238 KW=KW/1.1
      TYPE 38,PEN
      PEN=PEN*1.1
      GO TO 45
246 PEN=PEN/1.1
      TYPE 43,OPEN
      OPEN=OPEN*1.1
      GO TO 45
247 OPEN=OPEN/1.1
      TYPE 47,DEL
      DEL=DEL*1.1
      GO TO 45
244 DEL=DEL/1.1
      TYPE 48,NEL
      NEL=NEL*1.1
      GO TO 45
239 NEL=NEL/1.1
      TYPE 49,CEL
      CEL=CEL*1.1
      GO TO 45
245 CEL=CEL/1.1
      TYPE 39,SKW
      SKW=SKW*1.1
      GO TO 45
251 SKW=SKW/1.1
      TYPE 40,HTGLD
      HTGLD=HTGLD*1.1
      GO TO 45
```

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252 HTGLD=HTGLD/1.1
    TYPE 54,EHFT
    EHFT=EHFT*1.1
    GO TO 45
254 EHFT=EHFT/1.1
    TYPE 55,EHEL
    EHEL=EHEL*1.1
    GO TO 45
255 EHEL=EHEL/1.1
    TYPE 51,DKW
    DKW=DKW*1.1
    GO TO 45
240 DKW=DKW/1.1
    TYPE 52,DMWH
    DMWH=DMWH*1.1
    GO TO 45
253 DMWH=DMWH/1.1
    TYPE 53,NMWH
    NMWH=NMWH*1.1
    GO TO 45
241 NMWH=NMWH/1.1
    TYPE 41,SRATE
    SRATE=SRATE*1.1
    GO TO 45
242 SRATE=SRATD/1.1
    TYPE 42,RDIF
    RDIF=RDIF*1.1
    GO TO 45
243 RDIF=RDIF/1.1
    GO TO 45
154 Q=5
155 FORMAT (/////////)
    DO 170 I=3,2,-1
    TYPE 155
    TYPE 47,DEL
    TYPE 48,NEL
    TYPE 49,CEL
    TYPE 42,RDIF
    IF (I.EQ.3) TYPE 106
    IF (I.EQ.2) TYPE 105
    TYPE 155
    TYPE 155
    TYPE 143,CONS(I)
    TYPE 161,YI,AC(I)
    TYPE 163,YI,CT(I)
    TYPE 147,YI,BT(I)
    TYPE 165,BCR(I)
    TYPE 137,YI,C(I)
170 TYPE 155
    GO TO 31
160 TYPE 104
    TYPE 155
    TYPE 137,YI,C(1)
    TYPE 155
    CALL EXIT
    END
```